NEWFOUNDLAND
OCEAN
INDUSTRIES
ASSOCIATION

Conference Proceedings

"Newfoundland Offshore: Project Issues"

St. John's, Newfoundland
June 6-8, 1989

PROCEEDINGS

OF

NOIA CONFERENCE '89

ST. JOHN'S, NEWFOUNDLAND
JUNE 6 - 8, 1989

"NEWFOUNDLAND OFFSHORE: PROJECT ISSUES"

SPONSORED
BY

NEWFOUNDLAND OCEAN INDUSTRIES ASSOCIATION
P.O. Box 487
St. John's, Newfoundland
A1C 5K4
(709) 753-8123

89-05124/

TABLE OF CONTENTS

PAGE

CHAIRMAN'S MESSAGE i

CONFERENCE COMMITTEE ii

PROGRAM iii

CONFERENCE PAPERS:

SESSION I FLOATING PRODUCTION SYSTEM OPTIONS

- Deep Water Field Developments In Brazil
  Ilton J. Rossetto 1
- Production Vessel Design For Ice Infested
  Waters Fathi Khalil 31
- Concept For Conversion Of Associated Gas
  to Methanol Terje P. Tellefsen 55
- Installation Of Process Plants On Existing
  Semisub Units Rationalized Hans Rolfsman 78
- Concrete Semi-Submersible For The Grand
  Banks Gerry Germain 100
- A Cost Effective New Build Semi-Submersible
  Craig Lang & Barry Ryan 134

SESSION II CERTIFICATION & QUALITY ASSURANCE

- A Modern Certification Scheme
  Lars Foyen 172
- Construction Phase Certification
  Requirements Dr. John Manning 190
- Benefits Of Documentation Control
  Tor Henrik Stavnes 210
- It's A Jungle Out There
  Larry Rogers 262
- The Application Of Quality Assurance To
  Hibernia: The Operator's Viewpoint
  John Copeland 269

SESSION II (CONTINUED) PAGE

* Assessment Of Quality Management Systems
Einar Rytting 281

* A Maintenance System Designed For Low
Cost Operations Kjetil M. Stuland 296

* A New Generation Control System
Leslie Gomm 311

SESSION III COST EFFECTIVE DESIGN & CONSTRUCTION

* Designing For Platform Removal
William Penney 324

* Techniques For Topside Weight Reduction
David Hewlett & Paul Wilson 335

* Drilling Module Weight Reduction
Arild Thorsrud 360

* Weight Savings In Drilling Facilities
Arne Lindekleiv 373

LUNCHEON ADDRESS (The Honourable Jake Epp, P.C.,M.P.) 390

LIST OF ATTENDEES 397

A MESSAGE FROM THE CHAIRMAN

The Newfoundland Ocean Industries Association (NOIA) was proud to host its 5th International Petroleum Conference (NOIA Conference '89) during the Offshore Newfoundland Petroleum Exhibition.

In a diversion from previous years, the Conference Committee issued a Call for Papers, which resulted in an overwhelming response of very high level Abstracts. From these were chosen the final speakers and the overall theme for the Conference-issues related to the upcoming projects offshore Newfoundland.

The technical content covered areas such as gas utilization, cost effective designs and construction, maintenance systems, and quality assurance.

The following are the 20 papers which were presented in the sessions.

I would like to take this opportunity to thank the members of my Committee for their assistance in putting together this program and to gratefully acknowledge for their continued support, the Atlantic Canada Opportunities Agency and the Department of Development and Tourism, Government of Newfoundland and Labrador.

DAVID FONG
Chairman

CONFERENCE COMMITTEE

DAVID FONG
Chairman, NOIA Director
RDS Engineering Limited

BRIAN JONASSON
Canada Newfoundland Offshore Petroleum Board

ROB STRONG
Capital Crane Limited

MARIA YABLON
NOIA

ADMINISTRATION

MARIA YABLON, Executive Director
NOIA

DEBORAH HARTERY, Secretary
NOIA

YVONNE HOLLOHAN, Secretary
NOIA

NEWFOUNDLAND OCEAN INDUSTRIES ASSOCIATION
(NOIA)

BOARD OF DIRECTORS

NATH COOPER	PRESIDENT
CLARENCE DWYER	VICE-PRESIDENT
ERIC PATEY	TREASURER
DAVID FONG	DIRECTOR
SHEILA SMITH	DIRECTOR
LEE SHINKLE	DIRECTOR
ROGER FLOOD	DIRECTOR
CHRISTINE FAGAN	DIRECTOR

PROGRAM

7:45 - 8:15	Registration
8:15 - 8:30	Official Opening The Honourable Clyde Wells Premier Government of Newfoundland & Labrador

SESSION I - FLOATING PRODUCTION SYSTEM OPTIONS

8:30 - 9:15	**DEEP WATER FIELD DEVELOPMENTS IN BRAZIL** Ilton J. Rossetto Petrobras - BRAZIL
9:15 - 10:00	**PRODUCTION VESSEL DESIGN FOR ICE INFESTED WATERS** Fathi Khalil SNC/Aker Engineering A/S - NORWAY
10:00 - 10:45	**CONCEPT FOR CONVERSION OF ASSOCIATED GAS TO METHANOL** Terje P. Tellefsen A/S Uglands Rederi - NORWAY
10:45 - 11:30	**INSTALLATION OF PROCESS PLANTS ON EXISTING SEMISUB UNITS RATIONALIZED** Hans Rolfsman GVA International Ltd. - ENGLAND
11:30 - 11:45	Coffee
11:45 - 12:30	**CONCRETE SEMI-SUBMERSIBLE FOR THE GRAND BANKS** Gerry Germain Bouygues Offshore Canada Limited - CANADA
12:30 - 1:15	**A COST EFFECTIVE NEW BUILD SEMI-SUBMERSIBLE** Craig Lang & Barry Ryan Seaways Engineering (UK) Ltd. - ENGLAND

Moderator: DAVID FONG

SESSION II - CERTIFICATION & QUALITY ASSURANCE

8:30 - 9:15	**A MODERN CERTIFICATION SCHEME** Lars Foyen Det Norske Veritas (Canada) Ltd.- CALGARY
9:15 - 10:00	**CONSTRUCTION PHASE CERTIFICATION REQUIREMENTS** Dr. John Manning Offshore Certification Bureau - ENGLAND
10:00 - 10:45	**BENEFITS OF DOCUMENTATION CONTROL** Tor Henrik Stavnes Ineco A/S - NORWAY
10:45 - 11:00	Coffee
11:00 - 11:45	**IT'S A JUNGLE OUT THERE** Larry Rogers Quality Management Institute (CSA)- CANADA
11:45 - 1:00	Break for Lunch
1:00 - 1:45	**THE APPLICATION OF QUALITY ASSURANCE TO HIBERNIA: THE OPERATOR'S VIEWPOINT** John Copeland Mobil Research & Development Corporation NEWFOUNDLAND
1:45 - 2:30	**ASSESSMENT OF QUALITY MANAGEMENT SYSTEMS** Einar S. Rytting EB Consultants A/S - NORWAY
2:30 - 3:15	**A MAINTENANCE SYSTEM DESIGNED FOR LOW COST OPERATIONS** Kjetil M. Stuland NO-HA Engineering A/S - NORWAY
3:15 - 4:00	**A NEW GENERATION CONTROL SYSTEM** Leslie Gomm Bailey Controls - CANADA

Moderator: BRIAN JONASSON

SESSION III - COST EFFECTIVE DESIGN & CONSTRUCTION

8:30 - 9:15	**DESIGNING FOR PLATFORM REMOVAL** William Penney University of Newcastle Upon Tyne ENGLAND
9:15 - 10:00	**TECHNIQUES FOR TOPSIDE WEIGHT REDUCTION** David Hewlett & Paul Wilson NorTek Engineering Inc. - ST. JOHN'S
10:00 - 10:45	**DRILLING MODULE WEIGHT REDUCTION** Arild Thorsrud Aker Drilling A/S - NORWAY
10:45 - 11:00	Coffee
11:00 - 11:45	**WEIGHT SAVINGS IN DRILLING FACILITIES** Arne Lindekleiv Maritime Hydraulics A/S - NORWAY

Moderator: ROB STRONG

1:00	Closing Luncheon Guest Speaker: **THE HONOURABLE JAKE EPP, P.C., M.P.** **Minister** **Energy, Mines & Resources** **Government of Canada**

CONFERENCE PAPERS

SPEAKER : ILTON J. ROSSETTO

COMPANY : PETROBRAS

LOCATION : BRAZIL

TOPIC : DEEP WATER FIELD DEVELOPMENTS IN BRAZIL

BIOGRAPHY: Mr. Rossetto is a Technical Assistant to the Managing Director of Exploration & Production and has worked for the company since 1959. His experience covers thirty years in production operations in Brazil, the Middle East and North Africa. He holds a B.Sc. in Civil and Petroleum Engineering obtained from universities in Brazil and the Graduate Courses at the University of Oklahoma.

ABSTRACT

Located offshore Rio de Janeiro State, Brazil, Campos Basin has been during the last decade the most active area worldwide in producing oil and gas from subsea completed wells connected to floating production systems.

Since 1977, 22 FPS have been conceived and installed offshore Brazil and over 140 satellite wells have been subsea completed with wet christmas trees.

The discovery of two giant fields, Albacora and Marlim, in water depths from 200 to 2,000 meters (600 - 6,600 ft) are leading PETROBRÁS to increase R & D efforts towards cost effective development of their reserves that may reach over 4 billion barrels of recoverable oil and 65 billion cu.m (2.3 TCF) of associated gas.

The development by stages of Albacora field was initiated in 1987, with a pilot system (FPSO) comprising six wells, producing 18,000 BOPD.

Similarly Marlim field development is being started with a pilot FPS with satellite wells to be completed at water depths from 600 to 800 meters (1980 - 2640 ft). This pilot is scheduled to be on stream by the second semester of 1990.

This paper provides a review of PETROBRÁS experience in designing and operating FPS and presents figures on capital and operating costs of the Albacora and Marlim initial development phases as well as points out the technological challenges to be overcome towards a cost effective development and operation of those two deep water giant fields.

INTRODUCTION

The Brazilian continental margin (Fig. 1) encompasses 1,720,000 sq. km (382 million acres) of sedimentary basins up to a water depth limit of 3,400 m (11,100 ft).

Exploratory drilling offshore Brazil started in 1968 in shallow waters. In this same year the first commercial oil discovery was made in Sergipe-Alagoas Basin.

However, the first milestone regarding oil strikes offshore Brazil, the discovery of Garoupa field, took place in 1974 in Campos Basin that became the most prolific petroleum basin of the country (Fig. 2).

Following a period of oustanding rate of exploratory successes comprising the discovery of 26 oil and 3 gas fields in water depths between 80 m (262 ft) and 200 m (650 ft) it was decided to lead drilling efforts in Campos Basin to waters gradually deeper (Fig. 3). As from 1977 around 90 wells have been drilled in water beyond 300 m (984 ft) being 22 drilled in waters deeper than 1,000 m (3,280 ft).

The discoveries of two giant fields, Albacora (1984) and Marlim (1985) constitute paramount events in very deep water exploration in a world scale. These fields, situated in waters 200 m (656 ft) to 2,000 m (6,560 ft) deep, bear jointly 18 billion barrels of oil in place allowing to estimate undeveloped reserves of over 4 billion barrels of crude oil and 65 billion cubic meters of associated gas (2.3 TCF).

The preliminary conception for the development by stages of Albacora and Marlim fields based on floating production systems (FPS) including semi-submersible stationary units and subsea completed wells equipped with wet christmas trees (WCT) is the main subject of this paper.

Besides, the major challenges to be overcome by PETROBRÁS in developing the technology required to produce oil from those deep water giant fields in a safe and cost effective way are also pointed out.

EXPLORATORY OUTLINE

Modern seismostratigraphic techniques including high quality seismic reflexion surveys have been key factors for new discoveries as well as for field developments in Campos Basin. The turbidite fan complexes that constitute both Albacora and Marlim fields were identified using those exploratory tools and later confirmed through drilling tests (Fig. 4).

Albacora is a 235 sq.km (58,000 acres) multi-pay oil and gas field (Figs. 5 and 6) exhibiting 8 different turbidite sandstone reservoirs ranging from Middle Cretaceous to Late Tertiary (Albian to Miocene in age).In some areas several pays appear stacked at depths between 2,350 m (7,700ft) and 3,200 m (10,500ft). The crude oil gravity decreases upwards varying from 30 to 18 degrees API. The maximum known net pay is 65m (213 ft) and the average net pay is 22m (73 ft). The average porosity is 17% associated with effective permeabilities of 10-50 mD in the Cretaceous sandstones and 30% porosity with 200-1,000 mD in the Tertiary reservoirs.The original oil in place of Albacora field has been evaluated at over 4 billion barrels pooled beneath waters from 200 m (656 ft) to 2,000 m (6,560 ft) deep.

Marlim field is a 160 sq.km (39,500 acres) single Oligocene oil pay accumulation bearing over 8 billion barrels of oil. Including its south, northern and eastern extensions, the so-called Marlim Complex spreads over 347 sq.km (86,000 acres) comprising four oil accumulations (Figs.7 and 8) having at least 6 billion barrels of oil in place. Water depths in the Complex span from 200m (650 ft) to more than 2,000 m (6,600 ft).

The southern part of the Complex exhibits a less simple geology featuring four stacked Oligocene pays; also an Eocene reservoir appears locally. Conversely the oil gravity which is 19-20° API in the northern accumulation improves to 27° API in the southern one. Reservoir targets occur at depths between 2,500 m (8,200 ft) and 2,700 m (8,860 ft) showing porosities from 11 to 31% with permeabilities in the range of 100 mD to over 2,000 mD.

Other turbidite fan complexes similar to Albacora and Marlim fields are expected to spread over Campos Basin area beyond 400 m (1,300 ft) water depth. The prospective area measures 65,000 sq. km (16 million acres).

Fifteen exploratory wells are to be drilled this year in waters deeper than 400 m (1,300 ft). Moreover ten leads identified in deep waters, north and south of Albacora and Marlim fields, are scheduled to be tested in the early nineties. To better support these drillings 50,000 km of 3 D seismic will be shot in 1989/90.

The high rate of success and the world scale size of the discoveries already made stimulate PETROBRÁS to proceed with Campos Basin deep water exploration and to extend its efforts to deep water areas in other offshore basins of the country.

EXPLOITATION BACKGROUND

The offshore Brazilian challenge extending exploratory works to water depths over 100m (328 ft) gave its first result in 1974 with the discovery of Garoupa field in Campos Basin, by the 1-RJS-9A wildcat.

The heavy dependence of the country on oil imports at that time coupled with the oil price shock of 1973, has led PETROBRÁS to search for non-conventional offshore production systems aiming at anticipating the beginning of production from new discoveries, thus reducing the import expenditures.

Besides the economic factors, the setting up of early production systems allowed PETROBRÁS to start a strong development of offshore technologies regarding both equipments and installation activities as well as operation.

Hence some highlights should be stressed:

Aug. 1977 - Start-up of Enchova FPS through a semi-submersible unit producing from a single completed well.

Jan. 1979 - Start-up of the Garoupa-Namorado one atmosphere FPSO through nine subsea completed wells encapsulated with wellhead cellar and connected to one multiplexed electrohydraulic control manifold installed on the sea floor. A converted tanker to process and store the oil production and to flare the associated gas, plus two mooring and offloading towers complete the system.

Apr. 1979 - Achievement of the water depth record on wet christmas tree installation through the subsea completion of a well at 189m (620 ft) water depth (Fig. 9).

Dec. 1982 - Start-up of the Bonito FPS through wells located in a wet subsea template-manifold installed at 190m (623ft), plus some satellite subsea completed wells pulled in the manifold through flexible lines bundle.

Aug. 1983 - Start-up of associated gas compression and transmission to shore from the Bonito FPS - the first operation of this kind in the world.

Jul. 1985 - Start-up of gas lift operations into one wet christmas tree completed well in Pirauna field at 233m (765 ft) water depth.

Set. 1985 - Beginning of water injection through one wet christmas tree well completed as a satellite of the Namorado Fixed Platform.

Jul. 1987 - Performing of a cased-hole production test in the well 1-RJS-367 (Albacora field) at 1,565m (5,133 ft) water depth - a world record.

Oct. 1987 - Installation of a CALM type buoy at the Albacora FPS at 230m (754 ft) water depth - a world record.

Jan. 1988 - Diverless completion of well RJS-376 D, in Marimba FPS, at 492m (1,614 ft) - a world record held until November 1988.

In addition to these data, 22 floating systems have been installed, 10 such systems have been redeployed whereas the remaining 12 are still in operation (Table 1). Also around 500 km of flexible lines of various diameters, 16 subsea manifolds and 150 wet christmas trees have been installed.

Presently three new systems are being commissioned to be installed in Marimbá, Marlim and Albacora fields, in water deeper than 400m (1,520 ft) using semi-submersibles as stationary production units.

TECHNOLOGICAL CHALLENGES

The discovery of Marlim and Albacora giant petroleum fields in typical turbidite sands of fairly young age call the attention to accumulations of this kind along the present continental margins, in most cases in deep waters. The development of technology to exploit those reservoirs is of uppermost importance. Floating systems with subsea completions are very attractive solutions even beyond the 1,000 meters (3,280 ft) water depth for their simplicity, safety and its competitive cost. Brazilian successes are giving to the industry the motivation to look for new fields in deep waters and to improve the technology for its exploitation.

In Brazil there is still a great potential for discoveries in Campos Basin along with a huge area adjacent to near 8,000 km of coast line. In the next ten years the domestic production may reach 1.5 million barrels per day. A substantial part of it will come from offshore fields; a good part of it from very deep waters in which the fields development will be dominated by FPS and subsea completions. The authors are confident that this scenario will also predominate in a worldwide scale.

Besides the challenges still being overcome in exploration and drilling in deep waters, there are several technological challenges in the production area comprising the field test of new equipments, the improvement of subsea installation procedures, and above all the achievement of operational continuity within the standards of safety and economy.

Led by the experience acquired in drilling, installing and operating wet christmas trees and floating systems in deep waters, the Company is now giving more emphasis to joint development and redesign of the major components of FPS such as:

- diverless-guidelineless subsea trees including standardization of connections, controls, as well as the improvement of the technique to install wet christmas trees of the lay-away type.

- manifolds/templates safety operation conditions have received special attention as well as repair procedures, ROV interventions, multiplexed control systems and lines connections. It should be also mentioned the "in house" development by PETROBRÁS of the OCTOS-1000 template-manifold conceived for installation up to 1,000m (3,300 ft) water depth as well as the engineering of multiplexed control systems for subsea manifolds now in project phase.

- flow lines and risers, rigid or flexible, still require search for alternative materials to reinforce the internal structure of pipes as well as the development of new lay off procedures to overcome the more severe dynamic tension forces prevailing in deep water operations.

- remote control vehicles for surveillance, intervention and inspection of subsea installations.

- multiphase pumps for exporting production to shallow water platforms or to shore facilities.

- special designed semi-submersible production units for 1,000m (3,280 ft) water depth with safe-proof anchoring system, large area for production facilities and high deck loading capacity.

- composite materials for offshore structures aiming at reducing their weight and cost.

A hyperbaric center, installed in Rio de Janeiro, displaying facilities to simulate pressures up to 1,000m (3,280 ft) water depth is part of the strategy to help solving some of the problems related to deep water technology.

FIELD DEVELOPMENT CONCEPTION

The major characteristics of the development conceptions aiming at exploiting oil and gas fields based on FPS are the flexibility and mobility showed by these production systems.

Based on the experience acquired in the last 12 years on performing technical and economical optimization of the systems in operation, PETROBRÁS is confident that the conceptions of FPS used between 100m (328 ft) and 300m (984 ft) are suitable to be extended to the development of field located at water depths over 300m.

It is worthwhile mentioning that the technical and economical viability of any conception will be based on the system safety and simplicity taking into consideration all the specific factors involved in each design such as reservoir conditions, local conditions (climate, geography, etc.) and technical restrictions besides economic factors as capital and operating costs, early cash flows and investiment opportunities as well.

A comparative study of the various alternatives will provide the necessary input for the final decision on the system design.

Accordingly, to cope with the uncertainties of the geological model and primary production mechanisms of the sandstone reservoirs as well as with the technological and capital cost constraints related to the development of giants and very deep water fields, it has been decided to develop Albacora and Marlim by stages. Each stage will provide geological and reservoir performance information, related technology and early cashflow to support the following stages.

Going one step further a second decision has been made; each development stage will be based on the Floating Production System (FPS) conception, comprising floating production units and subsea completed wells.

This decision has been preceded by a sound analysis of the most feasible deep water conceptions taking into consideration both the technological challenges related to each design and the economical requirements (capital and operating expenditures) vis a vis the next decade crude oil price stabilization scenario.

The use of conventional steel fixed platforms has been accepted as having reached its water depth limit with the installation of the Bullwinckle platform at 412m (1,353 ft) in the U.S. Gulf of Mexico.

Compliant towers similar to the Roseau and Gamma Tower design concepts have been discarded on the basis of the poor soil conditions and high velocity of the bottom sea currents prevailing in Campos Basin. Besides no related field proven experience with this kind of compliant structures has yet been acquired.

The Tension Leg Wellhead Platforms combined with the concept of a Centralized Shallow-Water Processing Platform which may constitute an ideal design for the development of compact and deep reservoir targets to be drained by a large number of low productivity wells, have also been discarded taking into consideration the characteristics of Albacora and Marlim fields such as :

- large areal extent requiring a large number of platforms;

- shallow depth and poor consolidation of the sandstone pay zones implying the drilling of highly deviated holes that may impair a successful performance of gravel packing operations for sand control;

- high productivity index of the main reservoirs allowing a wide well spacing production pattern that favors the reservoirs drainage through subsea completed satellite wells connected to semi-submersible production units;

- high viscosity and low gas-oil ratio of the produced fluid impairing multiphase flow production to processing facilities located at large distances from the wellhead platforms. This constraint may be overcome in the near future provided that the project of subsea multiphase pumps turns out to be successful.

ALBACORA FIELD

Development and production system

Albacora field is being put on stream in four stages following a pay as you go conception. Each stage will provide information, technology and cash flow for the following stages.

Phase I - In operation since October 1987, Phase I comprises six exploratory wells subsea completed in waters 305m (754ft) to 419m (1,374 ft) deep (Fig. 10). Production averages 18,000 BOPD and 250,000 cu. m/day (9 MMSCFD) of associated gas.

Producing wells are connected to a diver-assisted subsea manifold from which oil and gas multiphase production flows to a monobuoy where a process tanker is moored and anchored at 230m (754 ft) water depth. This monobuoy is equipped with a specially designed multi-chamber swivel. Producing facilities on the tanker enables oil and gas separation, the treatment, stabilization and transference of oil and gas as well as water disposal. Oil is pumped through the monobuoy swivel and a flexible subsea pipeline to a second buoy system where a shuttle tanker is moored. Gas is compressed on the process tanker and exported through the monobuoy swivel and a rigid pipeline to the Garoupa field fixed platform.

Phase IA - This enlargement phase, to be completed by the middle of 1989, is adding six wells to the previous Phase I (Fig. 10).These wells are being drilled in water depths of 260m (850ft) to 600m (1,970 ft). Wet trees will be connected to the process tanker through a second diver-assisted subsea manifold installed in Phase I. Control, processing and loading systems have already been sized in Phase I to deal with the production increase of Phase IA.

The cost of this phase including wells drilling and completion will be about US$ 95 million for an additional production of 18,000 BOPD and 300,000 cu. m/day (10.5 MMSCFD) of associated gas.

Phase II - This phase, with initial production scheduled to start in 1991, will comprise the full development of the Albian Namorado sandstone reservoir and the west portion of the Oligocene reservoirs to a water depth limit of 700 m (2,300 ft). Characterized by low productivity, Namorado pay zones will require a narrow well spacing production pattern with 46 wells to accomplish efficiently, the reservoir drainage (Fig.11). The west portion of the Oligocene reservoirs will comprise 70 wells increasing the overall total of Phase II to 116 producing wells.

Taking into consideration the large areal extent and shallow depth of the pay zones below the mudline, wells will be directionally drilled from clusters or template-manifolds and connected to 15 diverless subsea manifolds each one gathering 8 wells. Well controls, processing and export facilities as well as equipment for water injection and gas lift will be installed on 3 converted semi-submersibles.

The 12 producing wells of Phases I and IA will be redeployed to the FPSs system of Phase II and are included in the total of 116 wells.

Oil will be exported to Garoupa through a 24 in. x 65 km (40.4mi.) pipeline to be laid between Albacora and Garoupa fields.

Gas will be transferred to the Garoupa fixed platform via the already installed 16 in. rigid pipeline.

Peak production from Phase II, forecast to occur in 1993, will reach 110,000 BOPD and 1.6 MM cu. m/day (57 MMSCFD).

Phase III - This phase comprises the development of the east deep water portion of the Oligocene-Miocene reservoirs through wells drilled from clusters or template-manifolds, subsea completions and semi-submersible floating production units at water depths from 1,100m (3,600 ft) to beyond 1,220m (4,000 ft) (Fig.11). About 95 wells connected to 13 diverless manifolds will produce to three FPSs, where oil and gas will be processed and exported to shore via a booster pump platform installed in Phase II. Initial production is planned to start by 1993 and peak production to be achieved in 1997 with 296,000 BOPD and 5.4 MM cu. m/day (192 MMSCFD) of associated gas.

As pointed out in the conception analysis discussion, the FPS design presented for Phases II and III constitute a Preliminary Exploitation Plan which will undergo periodical revisions aiming at introducing technological developments and cost effective solutions that may arise from the intensive R.& D efforts being made by the company either exclusively or through joint projects.

Development and production system

Prior to the global development phase, Marlim field will be long run tested by a Pilot floating production system now being installed (Fig. 12).

The major objectives of the system are the evolution of wells behavior, primary production mechanisms, reservoirs continuity and field performance of subsea equipments and devices aiming at acquiring technology and operational reliability to proceed with the design of the global exploitation plan of Marlim field.

To reach those targets the Pilot FPS has been designed to provide information on:

- mooring systems and flexible risers performance at 600m (2,000ft) water depth;
- design and field test of gravel pack systems submitted to high flow rates;
- multiphase flow of 19° API crude and associated gas to large distances (up to 7 Km) under low temperature conditions;
- maintenance and inspection of subsea equipments through remote operated vehicles (ROV and RCV);
- installation of guidelineless and diverless subsea equipment as well as workover jobs by DP vessels and conventionally moored vessels in deep waters up to 600m (2,000 ft);
- continuity of the sandstone reservoirs;
- **reservoir pressure behavior under natural depletion mechanisms.**

The conceived Marlim Pilot FPS, to be on stream by the first quarter of 1990 has the following main features:

- six producing wells subsea completed at water depths from 610m (2,000 ft) to 790m (2,600 ft) and connected, individually, to a converted semi-submersible moored in 600m (1,970ft) of water;
- spare connections for 4 additional wells to assure a plateau production of 52,000 BOPD and 600,000 cu. m/day (21 MMSCFD) of associated gas during the 4 years period scheduled for the Pilot operation;
- process capacity and utilities to handle 55,000 BOPD and 700,000 cu. m/day (25 MMSCFD) of associated gas;
- crude oil offloading system comprising two monobuoys anchored at 400m (1,310ft) to avoid production shutdowns during shuttle tanker replacements;
- gas export system via a 8 in. x 12 km rigid pipeline linked to the Albacora / Garoupa pipeline;
- capital cost estimate of US$ 316 million;
- production cost of US$ 9.8/boe.

Concerning the exploitation plan of Marlim Field, a preliminary conception based on FPSs and subsea completions has been worked out. The plan foresees a production-injection pattern of 155 wells with a well spacing of 1 Km. The field development phase will start in 1991 lasting around 10 years.

First oil production is forecast to be on stream by the beginning of 1992 through the FPSs located at water depths shallower than 800m (2,630 ft). Peak production is estimated to reach 430,000 BOPD and 8.2 MM cu. m/day (290 MMSCFD) of associated gas.

The gathering system will be based on around 20 multiplexed control diverless subsea manifolds interconnected to several converted semi-submersibles drilling platforms and specially designed production platforms.

A booster pump platform located at 700m water depth (2,300 ft) will provide the required power for oil and gas transfer to shore.

Should the multiphase pump development or the conceptions of subsea oil and gas handling systems be successful; Marlim production system will incorporate those technologies.

Another feature of the preliminary plan being submitted to a sound review is the drilling technique to be employed, that is, vertical satellite wells versus highly deviated holes drilled from templates or template-manifolds.

The background to be acquired from the Marlim Pilot coupled with the intensive efforts being made on Research and Development to overcome the challenge of producing oil from deep water fields under a safe and cost effective basis will provide the necessary means to transform the giant Marlim Field Exploitation Plan into a solid and successfull reality.

FINAL REMARKS

After 12 years of operational experience with floating production and subsea systems, optimizing and simplifying several FPS conceptions, PETROBRÁS has crossed a new frontier - the achievement of production in water depths beyond 400 meters (1.312 ft).

The further exploitation in the next years, of the Marimbá, Albacora and Marlim fields located in water depths between 400m-2000m (1.300ft - 6.550ft), will lead to the development of new technologies and equipments as well as to new ideas on subsea conceptions.

The high cost and the risk involved in deep water production call for systems with enough flexibility and mobility for redeployment. Both conditions are entirely fulfilled by the floating production systems with subsea completions.

CREATIVITY, KNOWLEDGE, EXPERIENCE, SAFETY and DARING are the fundamental principles to conquer deep waters.

REFERENCES

1. Freire, W. - "Campos Basin Deep Water Giant Field" - OTC 5970, Offshore Technology Conference, Houston, May 1-4, 1989.

2. Souza, J.M. et elll - "Marlim and Albacora Fields: Geophysical, Geological and Reservoir Aspects" - OTC 5894, Offshore Technology Conference, Houston, May 1-4, 1989.

3. Rodrigues, R.S.; Cordeiro, A. L. and Awad, S.P. - "OCTOS 1000 - A Deep Water Template Manifold" - OTC 5974, Offshore Technology Conference, Houston, May 1-4, 1989.

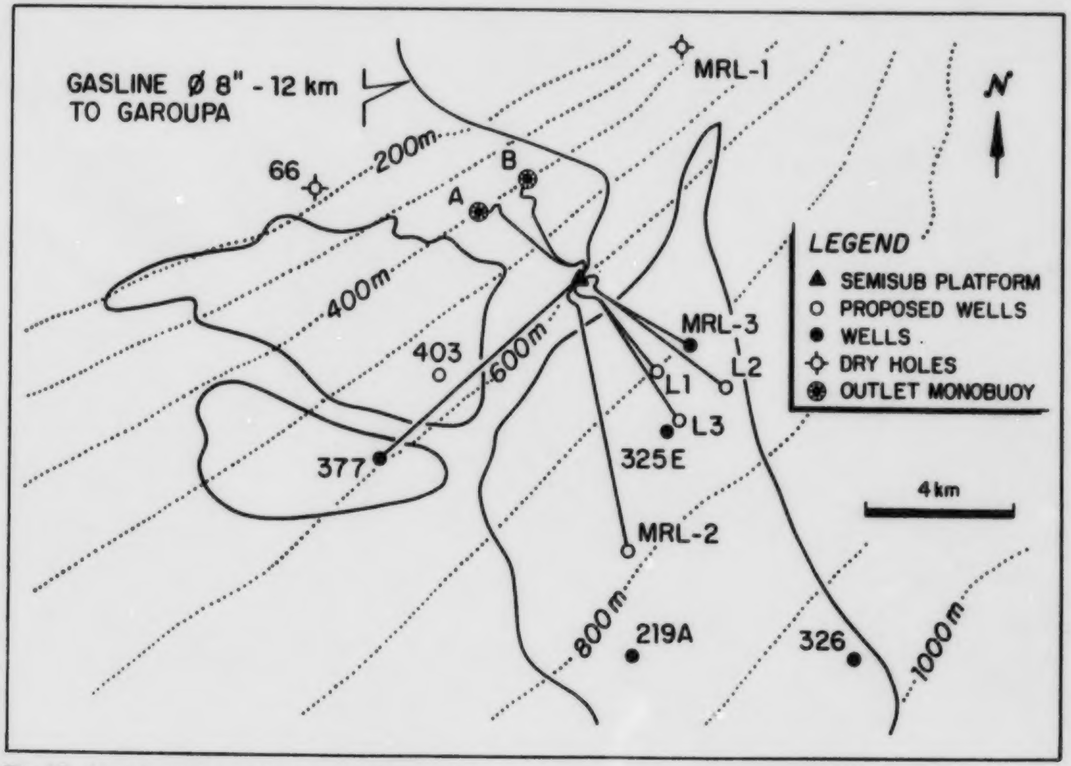

GASLINE Ø 8" - 12 km
TO GAROUPA
MRL-1
66
200m
B
A
400m
403
600m
377
MRL-3
L2
L1
L3
325E
MRL-2
800m
219A
326
1000m
N
LEGEND
▲ SEMISUB PLATFORM
○ PROPOSED WELLS
● WELLS
DRY HOLES
OUTLET MONOBUOY
4km

Fig. 12 - Marlim field - Pilot production system.

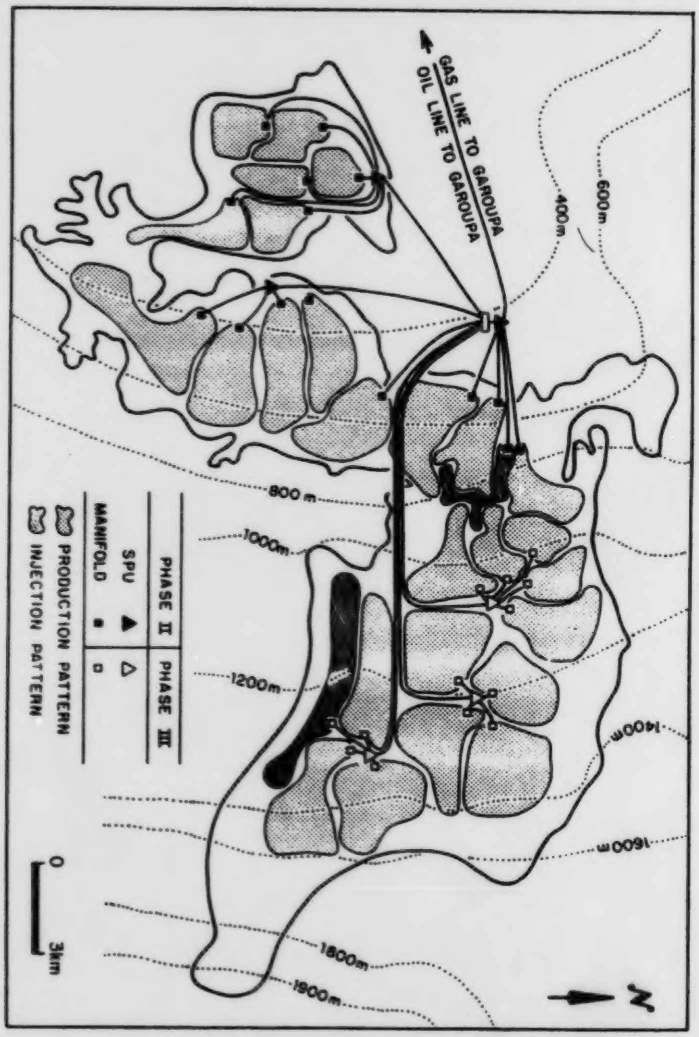

GAS LINE TO GAROUPA
OIL LINE TO GAROUPA
600m
400m
800 m
1000m
1200m
1400m
1600m
1800m
1900m
PHASE II
PHASE III
SPU
MANIFOLD
PRODUCTION PATTERN
INJECTION PATTERN
0
3km
N

Fig.11 - Exploitation plan for Albacora field.

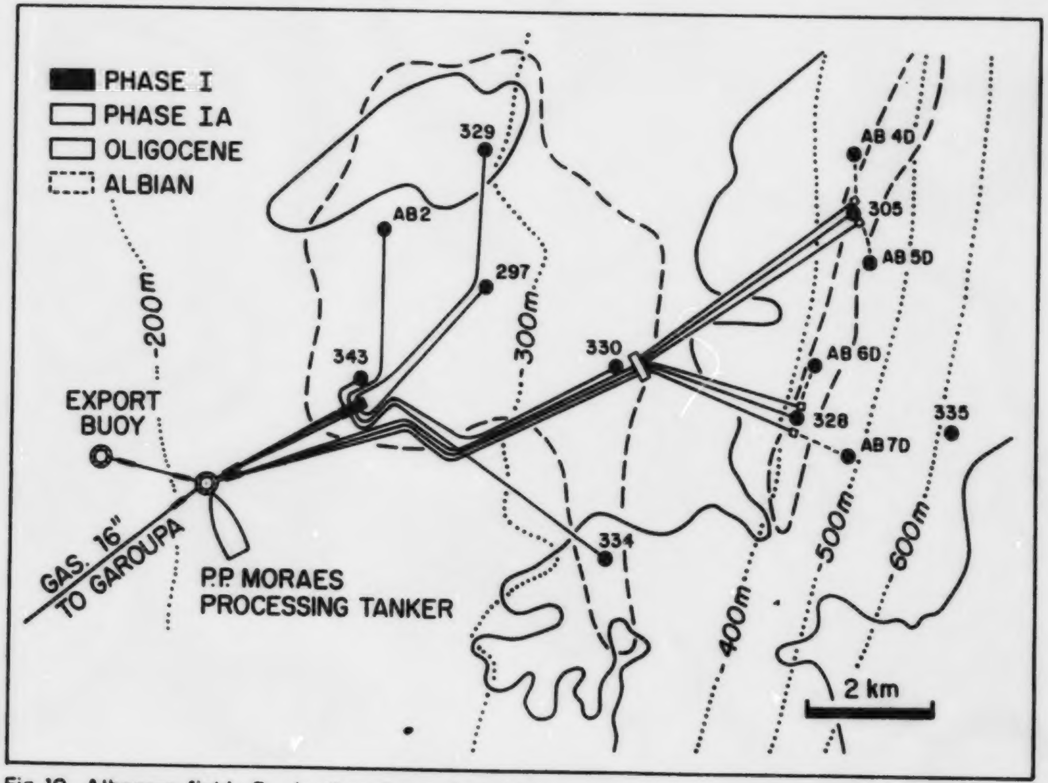

PHASE I
PHASE IA
OLIGOCENE
ALBIAN
329
AB2
297
343
-200m
300m
330
AB 4D
305
AB 5D
AB 6D
328
AB7D
335
EXPORT BUOY
GAS. 16" TO GAROUPA
P.P. MORAES PROCESSING TANKER
334
400m
500m
600m
2 km

Fig. 10 - Albacora field - Production phases I and IA.

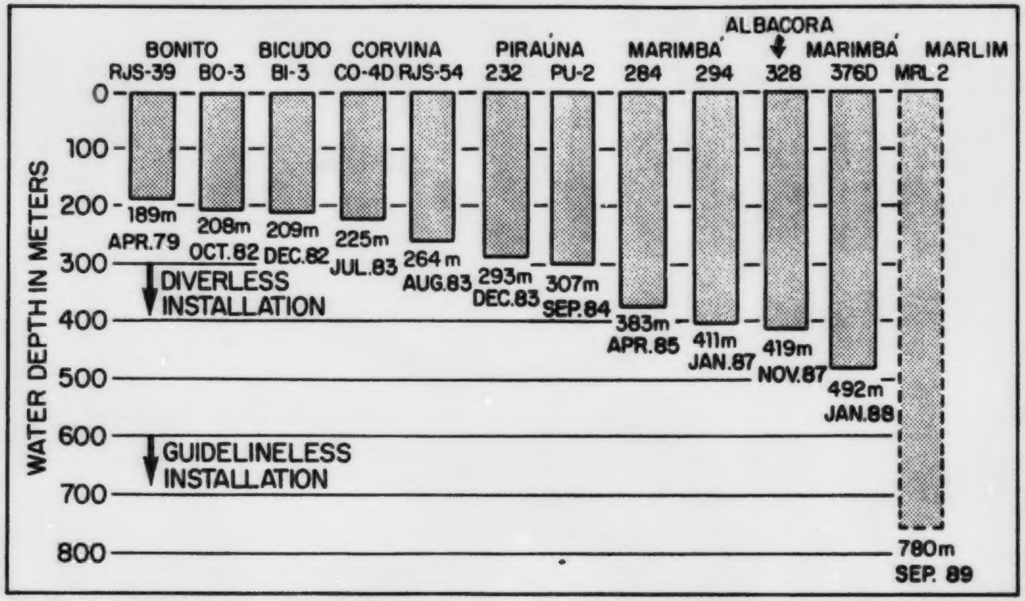
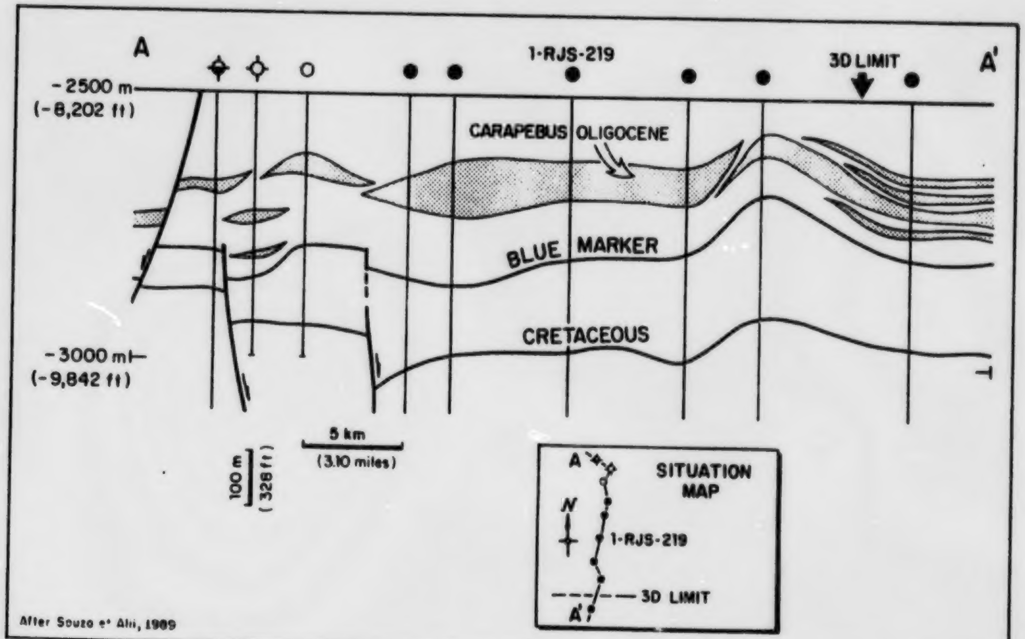


Fig. 9 – PETROBRÁS subsea completions – wet christmas trees.


A
1-RJS-219
3D LIMIT
A'
-2500 m
(-8,202 ft)
CARAPEBUS OLIGOCENE
BLUE MARKER
CRETACEOUS
-3000 m
(-9,842 ft)
100 m
(328 ft)
5 km
(3.10 miles)
SITUATION MAP
A
N
1-RJS-219
3D LIMIT
A'

After Souza et Alii, 1989

Fig. 8- Cross section on Marlim Field

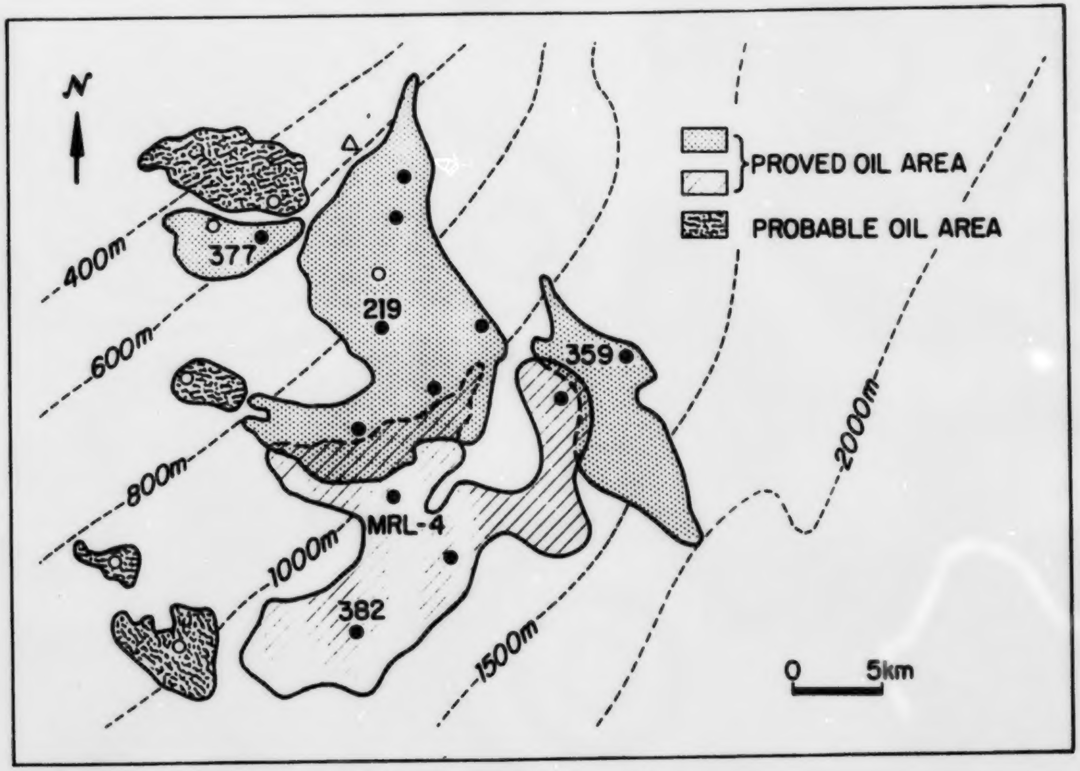
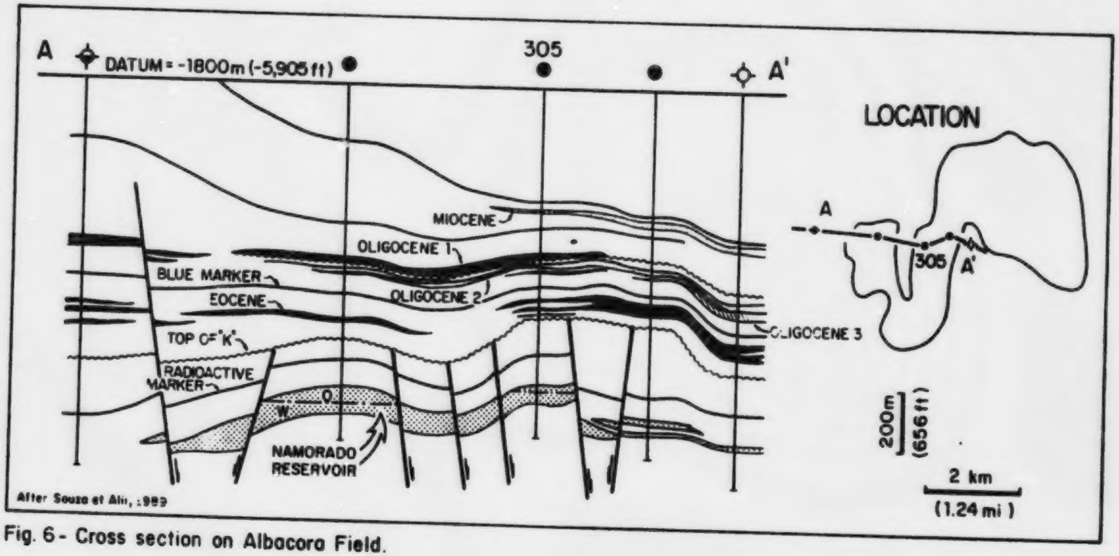

N
400m
600m
800m
1000m
1500m
2000m
377
219
359
MRL-4
382
PROVED OIL AREA
PROBABLE OIL AREA
0
5km

Fig. 7- Marlim Complex and probable adjacent oil accumulations.


A
DATUM = -1800m (-5,905 ft)
305
A'
MIOCENE
OLIGOCENE 1
BLUE MARKER
OLIGOCENE 2
EOCENE
OLIGOCENE 3
TOP OF "K"
RADIOACTIVE MARKER
O
W
NAMORADO RESERVOIR
LOCATION
A
305
A'
200m (656 ft)
2 km (1.24 mi)

After Souza et Alii, 1989

Fig. 6 - Cross section on Albacora Field.

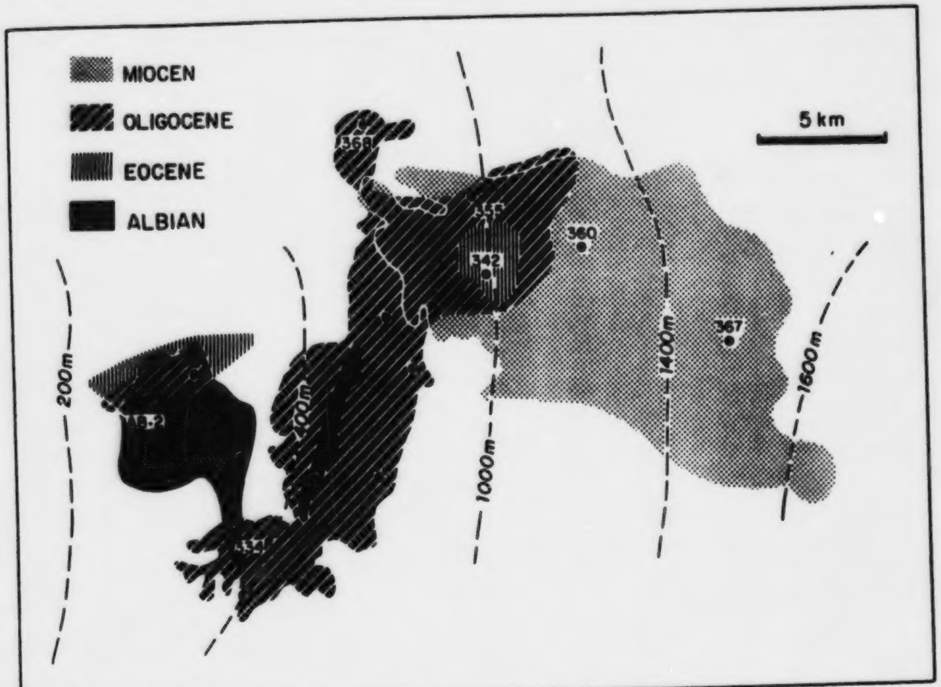

MIOCEN
OLIGOCENE
EOCENE
ALBIAN
5 km
200m
400m
1000m
1400m
1600m
368
342
360
367

Fig. 5 - Albacora field - Distribution of producing reservoirs.

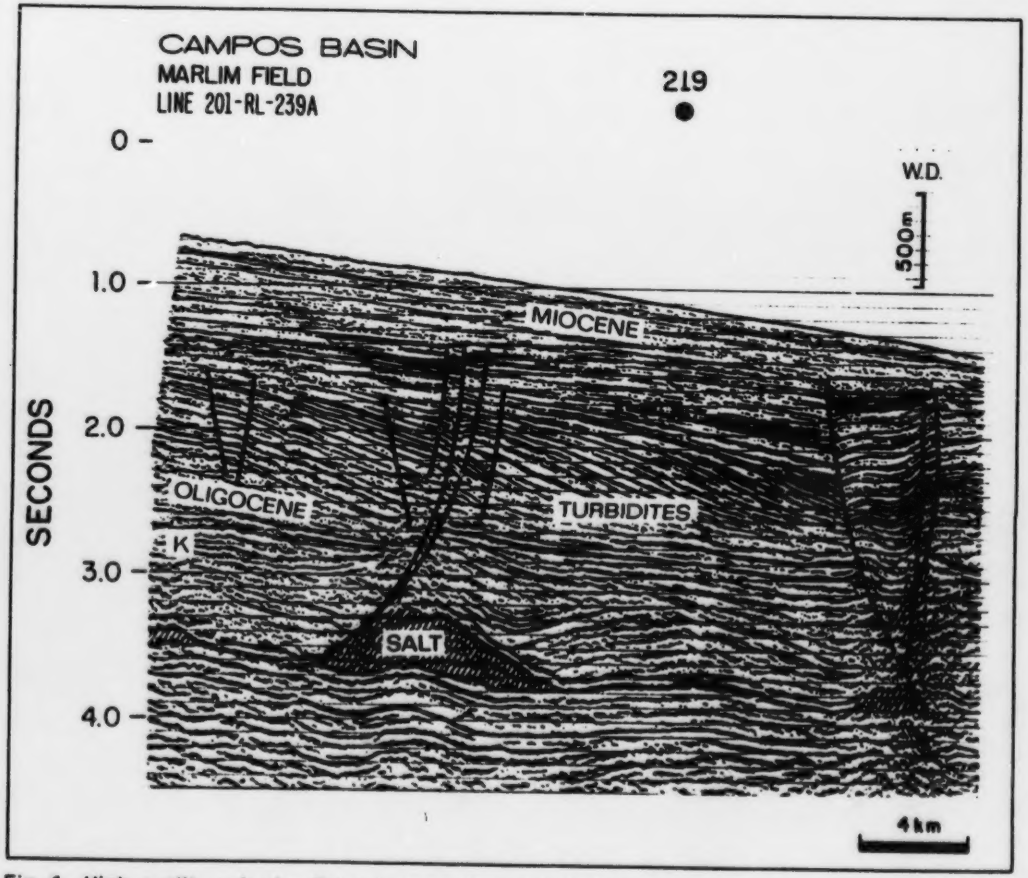

CAMPOS BASIN
MARLIM FIELD
LINE 201-RL-239A
219
0
1.0
2.0
3.0
4.0
SECONDS
W.D.
500m
MIOCENE
OLIGOCENE
K
TURBIDITES
SALT
4km

Fig. 4 - High quality seismic allows the mapping of turbidite reservoirs.

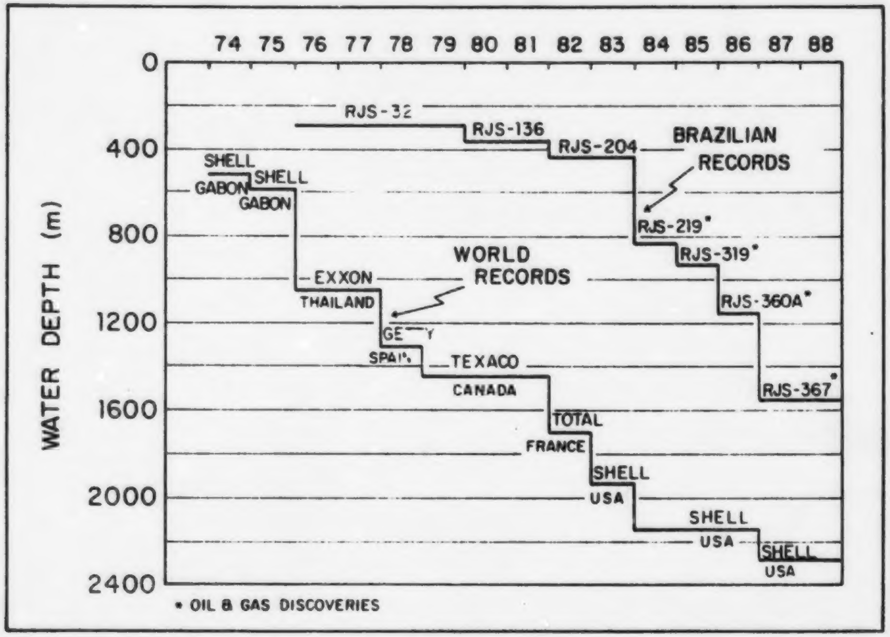


Fig. 3 - World and brazilian records on offshore drilling.

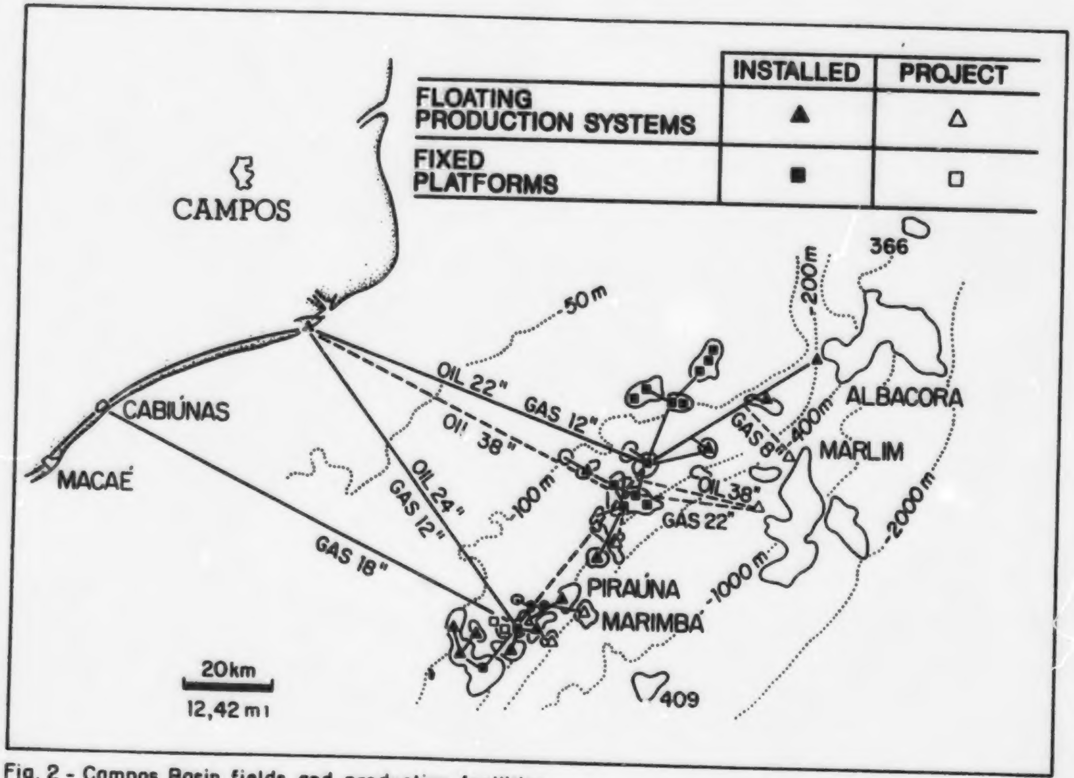

INSTALLED
PROJECT
FLOATING PRODUCTION SYSTEMS
FIXED PLATFORMS
CAMPOS
CABIÚNAS
MACAÉ
50m
100m
200m
400m
1000m
2000m
OIL 22"
GAS 12"
OIL 38"
OIL 24"
GAS 12"
GAS 18"
GAS 8"
OIL 38"
GAS 22"
ALBACORA
MARLIM
PIRAÚNA
MARIMBÁ
366
409
20km
12,42 mi

Fig. 2 - Campos Basin fields and production facilities.

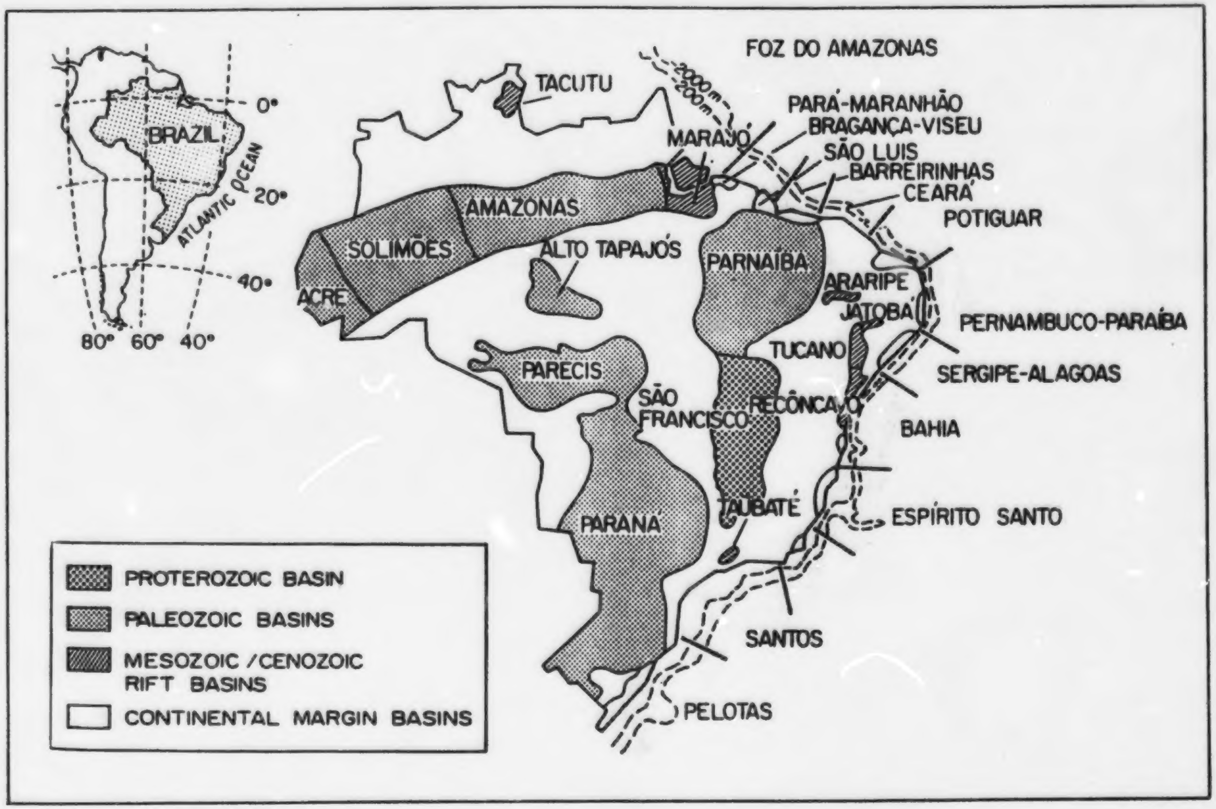

0°
20°
40°
80° 60° 40°
BRAZIL
ATLANTIC OCEAN
FOZ DO AMAZONAS
2000m
200m
TACUTU
MARAJÓ
PARÁ-MARANHÃO
BRAGANÇA-VISEU
SÃO LUIS
BARREIRINHAS
CEARÁ
POTIGUAR
AMAZONAS
SOLIMÕES
ACRE
ALTO TAPAJÓS
PARNAÍBA
ARARIPE
JATOBÁ
PERNAMBUCO-PARAÍBA
TUCANO
SERGIPE-ALAGOAS
PARECIS
SÃO FRANCISCO
RECÔNCAVO
BAHIA
TAUBATÉ
ESPÍRITO SANTO
PARANÁ
SANTOS
PELOTAS
PROTEROZOIC BASIN
PALEOZOIC BASINS
MESOZOIC /CENOZOIC RIFT BASINS
CONTINENTAL MARGIN BASINS

Fig.1- Brazilian sedimentary basins

TABLE 1

CAMPOS BASIN FLOATING PRODUCTION SYSTEMS IN OPERATION

(AS OF MARCH, 1989)

FIELDS	W. DEPTH STATIONARY UNIT. (m)	STATIONARY UNIT	Nº OF WELLS	WATER DEPTH RANGE OF THE WELLS(m)	PROCESSING CAPACITY	
					OIL (1000 BBL/D)	GAS (1000 m^3/D)
BADEJO	95	PETROBRAS-XXI	6	94- 99	49	1,200
LINGUADO	100	PETROBRAS-XII	11	96-108	50	1,000
TRILHA	105	TRANSWORLD-61	3	99-111	19	250
PARATI / ANEQUIM	107	NEPTUNE -7	5	96-117	20	200
MOREIA	114	PETROBRAS-XXII	6	113-120	10	180
VIOLA	127	ZEPHYR -1	7	125-126	23	200
BICUDO	200	PETROBRAS-VII	10	130-209	50	1,500
BONITO	190	PENROD-71	12	118-209	40	900
CORVINA	226	PETROBRAS-IX	6	225-255	40	180
PIRAUNA / MARIMBA	244	PETROBRAS-XV	12	230-492	38	300
ALBACORA	230	P. P. MORAES	8	250-420	60	450
ENCHOVA	120	SEDCO-135D	3	110-179	30	400
TOTAL			89		429	6,760

SPEAKER : **FATHI F. KHALIL**

COMPANY : **SNC/AKER ENGINEERING A/S**

LOCATION : **NORWAY**

TOPIC : **PRODUCTION VESSEL DESIGN FOR ICE INFESTED WATERS**

BIOGRAPHY: Mr. Khalil is the Senior Project Manager, Topsides & Floating Production Facilities. He holds both a B.Sc. and M.Sc. in Engineering and has had twenty-two years' experience in engineering, project engineering and management. The last eleven years has been in association with the offshore oil and gas industry. He was worked on land-based and offshore projects in the Middle East, Africa, Europe, the North Sea and North America. He is currently involved in finalizing the Terra Nova Preliminary Engineering Project.

INTRODUCTION

The environmental conditions in the Grand Banks region, off the east coast of Newfoundland, are characterized by a wind wave regime and frequent intense storms which are equivalent in severity and frequency to those in the North Sea.

Temperature, sea state, and wind conditions make superstructure icing a possibility anytime during the period from December through March. There is also a high incidence of reduced visibility, particularly during the summer months, when the range of visibility may be less than 0.5 nautical miles for 40% of the time.

Sea ice can be expected over parts of the Grand Banks between February and April. Sea ice intrusion at current wellsites averages about 40 days every 3 years.

In addition, and most significantly, is that the Grand Banks region (Figure 1) is in the path of drifting icebergs which are calved from the Northern glaciers and drift south with the Labrador current. Masses range from tens of tonnes to several million tonnes, the maximum credible mass being limited by the water depth.

The iceberg season on the Grand Banks averages four months with most icebergs detected between March and June. Average flux estimates suggest that about 30 icebergs will drift through a 1 degree square during any one year. The fifty and one hundred year fluxes are estimated to be 110 and 126 icebergs respectively.

This paper addresses the major features and design aspects of floating production platforms particularly when designed for service in ice infested waters.

Both the monohull (ship shape vessel) and the semi-submersible floating production concepts will be used as examples of floating production vessel design in ice infested waters.

DESIGN PRINCIPLES

Generally the principles and criteria for designing the topsides process plant and life support systems is nearly identical for both fixed and floating platforms. The main difference in the design is in the sub-structure where a floating unit, either a monohull or semi-submersible replaces the jacket, gravity base or other fixed structure.

Similar to fixed platforms, the topside facilities on a floating production platform are arranged in the following area sequence:

- Process area
- Oil and gas treatment
- Drilling area (optional)
  Light workover or complete drilling unit
- Utilities area
  Process related and life support systems
- Living quarters
  Accommodation, services, offices and control systems

This area segregation is based on the offshore safety principles developed and applied on North Sea offshore platforms. The rectangular shaped deck has been found to be the most favourable in terms of optimum utilization of available area and efficient layout. Figures 2 and 3 presents typical layouts for a monohull and a semi-submersible production vessel.

The floating production vessel will be winterized and designed according to known technology and well proven principles for motion stability and mooring systems. Loading conditions will vary slightly with the addition of icing loads due to sea spray or atmospheric conditions. Design for sea spray icing on vessels and marine equipment within the spray zone will be of greater concern than atmospheric icing in the Grand Banks region.

Structurally the floating vessel, either a monohull or a semi-submersible, designed for service in ice infested waters, does not differ from the regular floating production vessel design with the exception of some structural strengthening and structural protection of critical areas exposed to the risk of impact with smaller floating ice bits and limited thickness of sea ice.

Other most important design parameters that are considered specifically in connection with risk of iceberg collision are:

- Riser connection to vessel
- Mooring/anchoring system
- Protection methods and systems for subsea components

These features will be discussed further in the coming chapters.

RISER CONNECTION TO VESSEL

In view of the possibility of iceberg and sea ice intrusion onto the field and the assumed frequency of disconnection and reconnection operations, consideration has to be given to optimizing riser handling procedures. The presented concepts are based on the assumption that there is a need to connect a number of risers, between 15 and 20, to the floating production vessel. It is proposed that the risers are arranged in bundles and connected at the pontoon level on the semi-submersible or to the turret area in the monohull.

Semi-Submersible Production Vessel

Riser connection arrangements where all connectors are mounted on a single frame or two frames (Figure 4), facilitating simultaneous multi-connector handling, have been investigated. It has been concluded that while the use of such frames may potentially minimize the time required for planned disconnection and reconnection, there are a number of disadvantages associated with their use, including the potential for damage to frames and connectors during disconnect and reconnect operations and, most significantly, these options represent unproven technology. In addition, the handling of multiple riser bundles either by means of one or two structural frames will present additional problems and constraints during both disconnect and reconnect operations, increasing the possibility for riser damage under these circumstances. Accordingly, methods of handling the riser connectors individually are preferred. Although the connection of bundled riser systems to semi-submersible vessels is a field proven concept, innovative cost saving solutions have been sought for a development where the existence of sea ice may increase the frequency of disconnection and reconnection operations.

There is more than one connector type available on the market, most are field proven and meet the functional requirements for riser disconnect/reconnect.

Planned disconnection of the risers will form part of a detailed maintenance or abandon field procedure. Prior to carrying out any riser handling operations, the pipelines, flowlines and risers should be depressurized, flushed and the Xmas tree, riser base, riser isolation, topsides ESD and production control valves, will be closed. The vessel will be repositioned to the required riser disconnection location, which is selected such that the riser connector may be unlocked under purely axial load.

A typical riser quick connect/disconnect coupling is illustrated in Figure 5.

It is estimated that the planned riser disconnection operation can be completed in approximately 3 hours, depending on any problems which may be encountered. This does not include the time required to circulate and depressurize the pipelines, flowlines and risers.

Under extreme emergency conditions it may be found necessary to release the risers from their connectors at the vessel without the use of the winches. Depending on the time available, the options exist for simultaneous disconnection, when all the risers and riser bundles are released instantaneously, or for sequential disconnection. In both cases it will be preferable to bleed down pressures in the risers, if time permits.

Sequential disconnection will effectively reduce the risk of damage to both risers and connectors. This will be achieved by moving the vessel to locations which will enable the lower connector halves to be released at further distances apart than their centre to centre spacings on the pontoon. It is possible that the vessel can be moved up to 30 metres from its nominal position to release the first or last riser bundle, giving a maximum possible spacing of 10 metres between centres of risers or bundles as they release, and possibly also on the sea bed. It is estimated that this operation will take approximately 1/2 hour.

It is estimated, that with a normal ration of problems, reconnection will be achieved within a period of approximately nine hours.

Monohull Production Vessel

The design of a weathervaning monohull production vessel requires that the flexible riser system is connected to the anchored turret structure around which the ships hull rotates. The riser disconnect/reconnect system, which is located within the turret, must facilitate the handling of all risers both during planned and emergency operations.

Alternative riser handling procedures, ranging from the use of a dedicated handling system for each riser to the use of a single frame to support all 15 to 20 risers, have been evaluated. Because of the limited space availability in the turret it is considered that handling of each riser by means of a separate lifting system would result in interference and damage when the risers are disconnected or reconnected, either sequentially or simultaneously. The use of one or two frames to support the riser connectors will minimize the potential for connector damage and will enable the lift wires to be sufficiently well spaced such that interference does not occur.

During the evaluation of the dual and single frame options, the large, single frame design has been found to be particularly difficult to abandon safely. The preferred general arrangement of a double frame riser termination consisting of the steel structure, the riser connections and the isolation valves is illustrated in Figure 6.

Each termination incorporates a tubular steel structure which can be readily lifted into the turret without causing damage, and which will protect the connectors and valving when abandoned on the seabed. A single structural connector is fixed to the structure and is located in the centre of the group of risers.

The termination assembly will be lifted on reconnect with two wires, run from winches fitted to the turret walls. Final guidance of the lower structural connector half (mounted on the termination) into the upper structural connector half (mounted on the turret connector deck) will be achieved by means of guidepins fixed to the termination. A preliminary examination of the fabrication tolerances to be met, in order that successful connector engagement can be guaranteed, has indicated that termination structure fabrication can be carried out in accordance with standard industry practices.

Preparation procedures for riser disconnect will be similar to those for the semi-submersible, but the time required for lay down will be shorter.

MOORING/ANCHORING SYSTEM

Mooring system is designed for quick disconnection as compared with riser disconnection.

The frequency of disconnection and reconnection of the mooring system is expected to exceed that of the riser connection system. The mooring will be disconnected and the vessel put in a 'Dynamic Positioning' mode in situations when risk of impact with icebergs is high. The flexible risers would not be disconnected unless the most unlikely situation is reached where all ice management systems fail to divert the threatening iceberg.

Monohull Anchoring System

Two alternative anchoring disconnect/reconnect systems are proposed for the Monohull. Both systems make it possible for the vessel to disconnect all anchoring lines and lower them controlled to the sea bed in a controlled fashion.

Both systems use wire for disconnect and reconnect. and the anchor lines are laid on the sea bed with a marker buoy suspended from each line 'floating' below the sea surface.

One of the proposed systems allows the monohull to re-enter the location and reconnect the anchoring lines without assistance from other vessels (Figure 7). The other system needs assistance from an anchor handling vessel to reconnect the lines.

There will be two procedures for disconnecting:

1. Planned disconnect:

   The anchoring lines are lowered to the sea bed prior to releasing the risers (vessel in dynamic positioned mode).

2. Emergency disconnect:

   The anchoring system and the risers are simultaneously released.

During anchoring system disconnect, the move off location and the anchoring system reconnect, the vessel will be dynamically positioned (DP). The DP system should be designed to keep the vessel on location in a one year return storm condition. This condition will, therefore, be the maximum weather condition for a planned disconnect.

Semi-Submersible Mooring System

Similar to the monohull the mooring system can be disconnected in a planned or an emergency mode.

A number of suitable systems have been evaluated, these are:

System 1 (Figure 8)	The primary system is an in line weak link with a polypropylene rope as a back up.
System 2 (Figure 9)	Acoustically operated 'Remote Anchor Release System' (RAR) with an in line weak link or a polypropylene rope as a back up.

To facilitate reconnection of the lines after a disconnect, retrieval buoys are permanently connected to the chain left on the sea bed and the chain is retrieved by retrieving the buoys.

Disconnect of the anchor chains can be carried out by the crew on board the semi-submersible. Reconnecting the lines will require assistance from an anchor handling vessel. Reconnecting the lines may also be carried out without assistance from other vessels, but at this stage a procedure with assistance from an anchor handling tug is considered more reliable.

The methods by which the anchor lines are reconnected after a disconnect are identical for the two different release methods (Figures 10) as the chain is not required to be threaded through the lower fairlead.

In case of the propylene rope, the rope hangs through the fairlead and can be used in the reconnect.

When all the lines are reinstalled, the risers are retrieved. the anchor lines are tightened to the required tension and the SSPV after testing is ready to restart production. The pattern in which the anchor lines are laid down is shown on Figure 11. Anchor lines 2, 3, 5 and 8 are laid down with the semi in one location. After the lines are laid down, the semi is pulled about 20 metres to port where the rest of the lines (1, 4, 6, and 7) are laid down.

This will space the lay down point sufficiently to avoid marker buoys interference at the sea bed.

Assuming that two chains are disconnected simultaneously, total disconnect time (with contingency) will be approximately 40 to 60 minutes.

Total reconnect time is estimated to be 16 hours and the reconnect steps are as follows:

1. Retrieving and securing the length of chain suspended from the vessel.

2. Retrieving the subsea marker buoy and chain.

3. Reinstall weak link or RAR.

4. Lower chain into water and support chain.

5. Pull chain in on vessel and lower buoy.

An ROV may be required to connect the hook to the marker buoy.

Protection Methods for Subsea Components

All subsea production system equipment will be subjected to some probability of iceberg impact risk in the unlikely event that an iceberg cannot be diverted using the resources of the ice management system and traverses the field.

The probability of risk of iceberg impact varies from one subsea scenario to another. It also depends on the vulnerability of each component and the protection system applied.

The main subsea system components subject to the risk of damage due to iceberg collision are:

- Templates
- Riser bases
- Satellite wells
- Flowlines and pipelines
- Flexible risers
- Offloading stations

The most vulnerable pieces of equipment are the risers and offloading station. The next most vulnerable pieces of equipment are the templates when installed at mudline elevation. Caisson type Xmas trees, silo completions and the installation of templates in glory holes are alternative protection methods for reducing the probability of pollution and damage to wellheads and subsea components following iceberg impact.

The purpose of using the caisson completion system is to maximize the potential for well security following an iceberg impact on the wellhead. To achieve this the well casing program above the wellhead will consist of a caisson into which a lower valve block containing the lower master valves is installed. The lower valve block is situated below a weak joint in the caisson and is connected to the upper Xmas tree, installed at the mudline, by a high pressure tie back spool. The upper tree contains the upper master valves, swab valves and wing valves.

The caisson completion system is typically illustrated in Figure 12. In the event of iceberg impact, well security is intended to be maintained by limiting damage to the equipment above the weak joints. Only an iceberg traversing the field without rolling will exert a horizontal force on the upper Xmas tree on impact. If all the variable parameters associated with caisson collapse strength and soil properties are favourable, the weak joint will fail as intended. However, if rolling of the iceberg is considered, a vertical force may also be exerted upon the wellhead. The weak joints must therefore be designed to accommodate both horizontal and vertical forces to be effective in maintaining well integrity.

Submudline completions in drilled silos offer a feasible alternative for the protection of satellite wellheads. There are at least two alternative systems under the development, one of these is the successful installation of 7.3 metre diameter by 12 metre deep silos in the Beaufort Sea.

Alternative or additional protection methods like the excavation of gloryholes can be achieved by either vertical lift suction cutters, operated from trailing suction dredgers, or by seafloor crawling submersible suction cutters. Equipment developed by Alluvial Mining, the submersible crawler AMROD or the submersible crawler TRAMROD are most suitable for this application.

These methods represent the least cost options to achieve the required sub mudline depth of 15 metres for both silos and open gloryholes.

The installation of templates or gathering manifolds inside silo systems may have merit from a protection point of view but there are apparent disadvantages to this alternative approach to field development which will be reflected in incremental maintenance and iceberg damage repair costs. A cost benefit analysis will be required in order to determine the significance of these disadvantages relative to the advantages.

Well integrity can be maintained by utilizing one or more of the above mentioned systems, and the pollution risk is minimized by an effective warning system and operational procedures which include flushing of risers, flowlines and template headers prior to anticipated iceberg intrusion.

The satellite well protection system proposed is to use caisson type completion wells protected by a steel structure and installed in a gloryhole (Figure 13) at a depth where iceberg impact is probablistically acceptable. As the Newfoundland Grand Banks is located in an active fishing area, the potential for damage to exposed satellite wellhead equipment exists. The wellhead should therefore be protected by a structure which provides protection to the wellhead equipment from fishing gear and supply boat anchors. The configuration of the structure should also be designed to limit damage to fishing equipment. The proposed structure is free standing and totally independent of the wellhead equipment. The structure should be permanently secured to the seabed by piles which will transfer the structure weight and imposed hazard loadings to the underlying strata. Temporary support during installation is provided by fixed mudmats at each of the pile guide locations.

The capital cost of trenching has been compared with the potential financial exposure, with respect to scouring iceberg and fishing trawl gear damage. The cost savings applicable, depend on the flowline configuration and the depth of cover. In the case of towed bundle designs trenching would reduce potential ice damage costs. For single lines, additional costs associated with fishing gear damage, provision of insulation and required pipe weight coating have been found to be dependent on trench depth. It has been concluded that it will be cost effective to trench all lines to a depth of 2.0 m using a mechanical trencher. Significantly, the validity of this conclusion is dependent on the assumptions made concerning ice and fishing trawl gear damage.

An offloading system is required for the semi-submersible concept where export lines are not installed. The monohull vessel functions also as a storage vessel for the crude oil which is conveniently exported directly from the monohull to the shuttle tankers.

In the semi-submersible vessel scenario a flexible export riser transfers the crude from the vessel, via the riser base to an offloading buoy or base. There are several offloading systems available, but preference is for two offloading stations where the offloading base is installed in a gloryhole and protected by a steel structure with the flowline trenched (Figure 14). This will minimize downtime due to iceberg impact damage.

CONCLUSION

It is apparent that the specific design requirements for Floating Production Concepts in ice infested waters should be directed towards areas that are directly related to the following in order of priority:

- Safety of crew and vessel
- Minimization of the environmental pollution hazard.
- Risk of equipment damage and protection of the investment.
- Capital cost

It is concluded that with today's subsea technology and floating production development, it is both feasible and viable to develop offshore oil production fields in iceberg infested waters with reasonable capital cost expenditures and minimum environmental consequences.

The presented concepts, scenarios and proposals in this paper are the result of an evaluation performed based on simulated situations and assumptions. There is no doubt that other viable solutions could prove to be more effective under other field development scenarios.

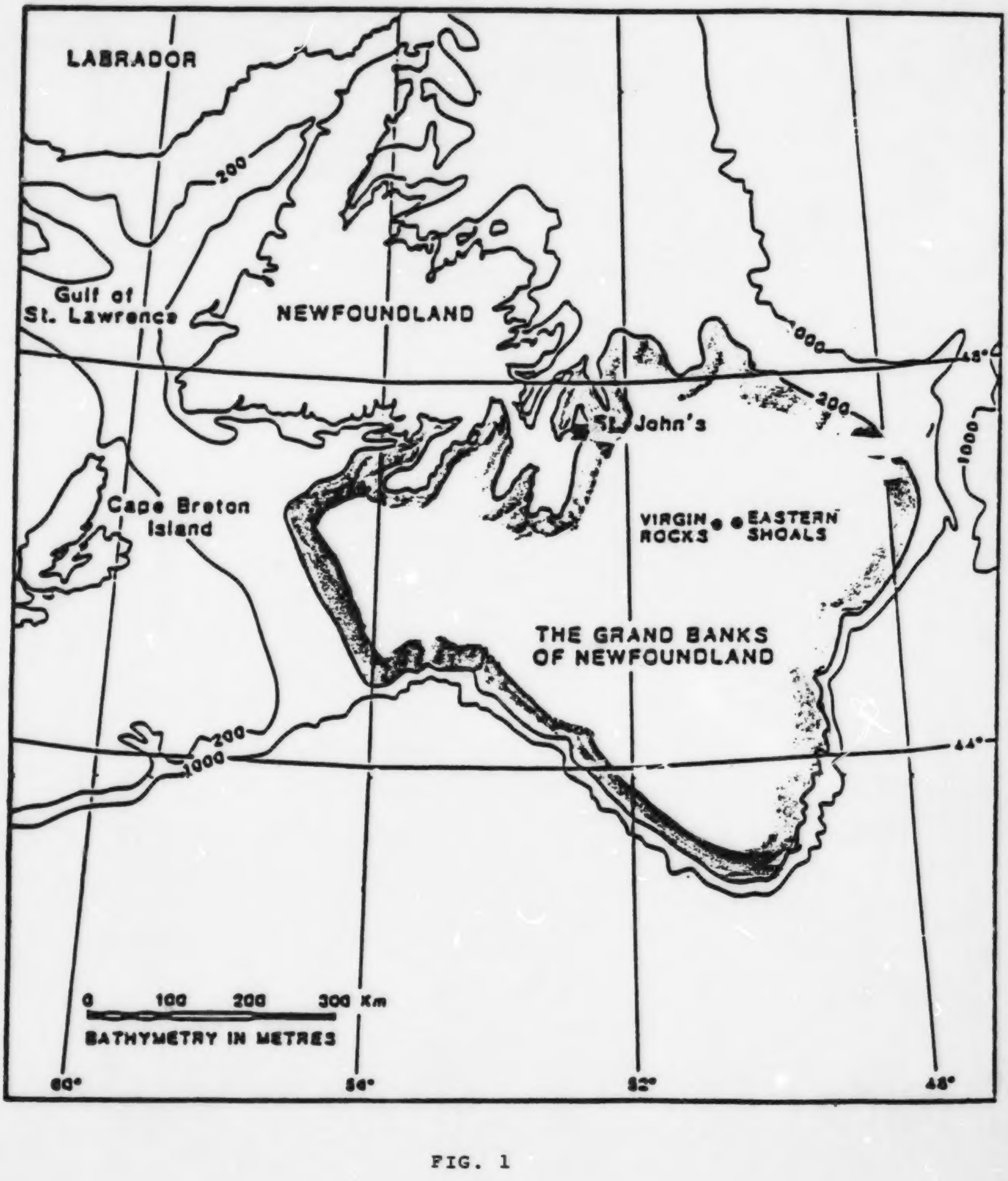
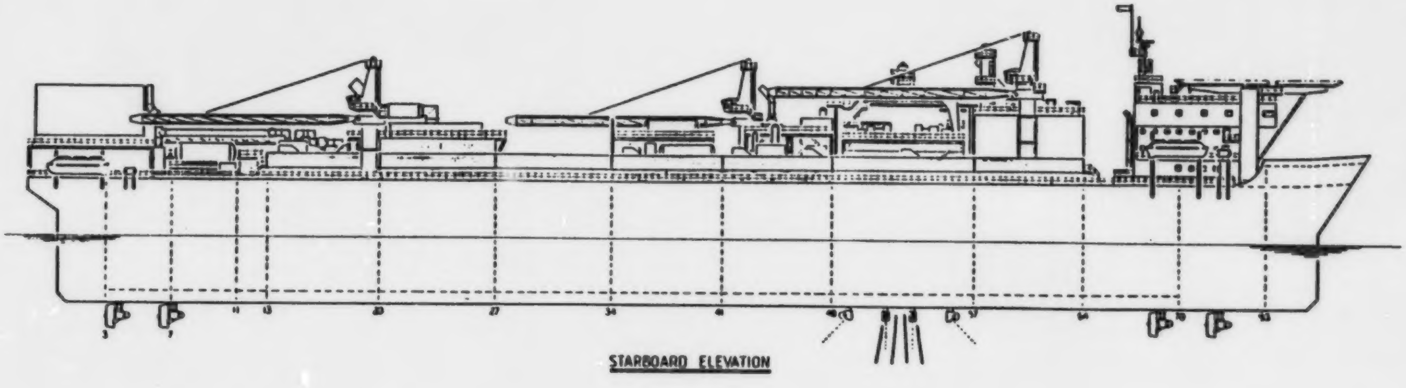
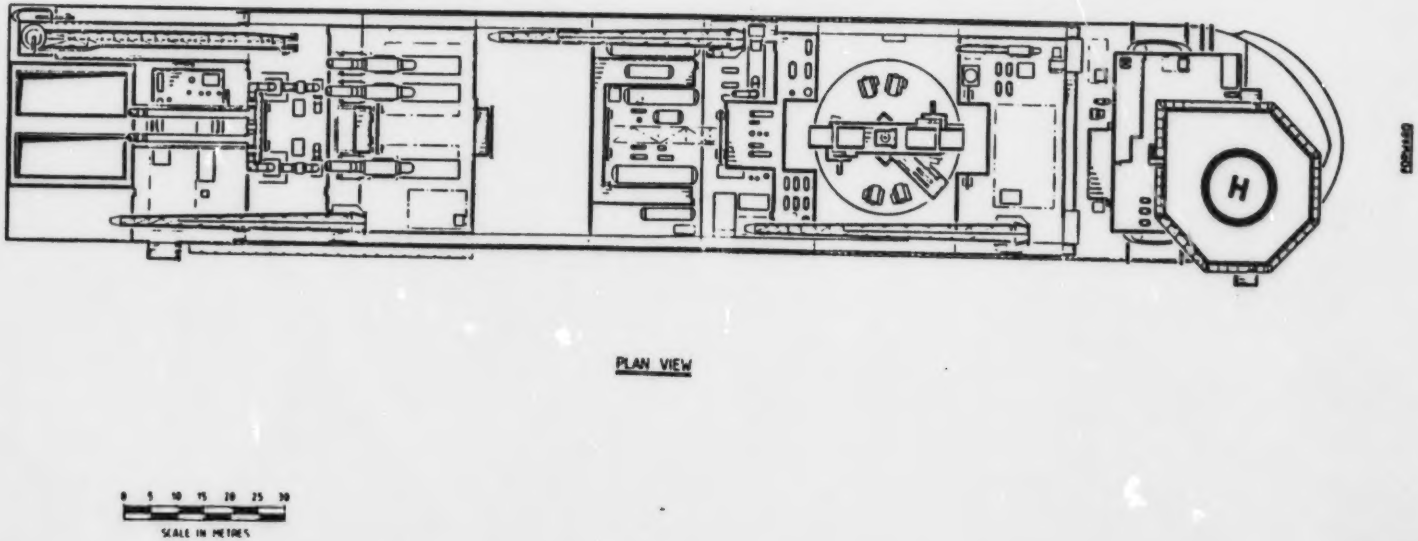

LABRADOR
Gulf of St. Lawrence
NEWFOUNDLAND
St. John's
Cape Breton Island
VIRGIN ROCKS
EASTERN SHOALS
THE GRAND BANKS OF NEWFOUNDLAND
200
1000
200
1000
200
1000
0 100 200 300 Km
BATHYMETRY IN METRES
60°
56°
52°
48°
48°
44°

FIG. 1

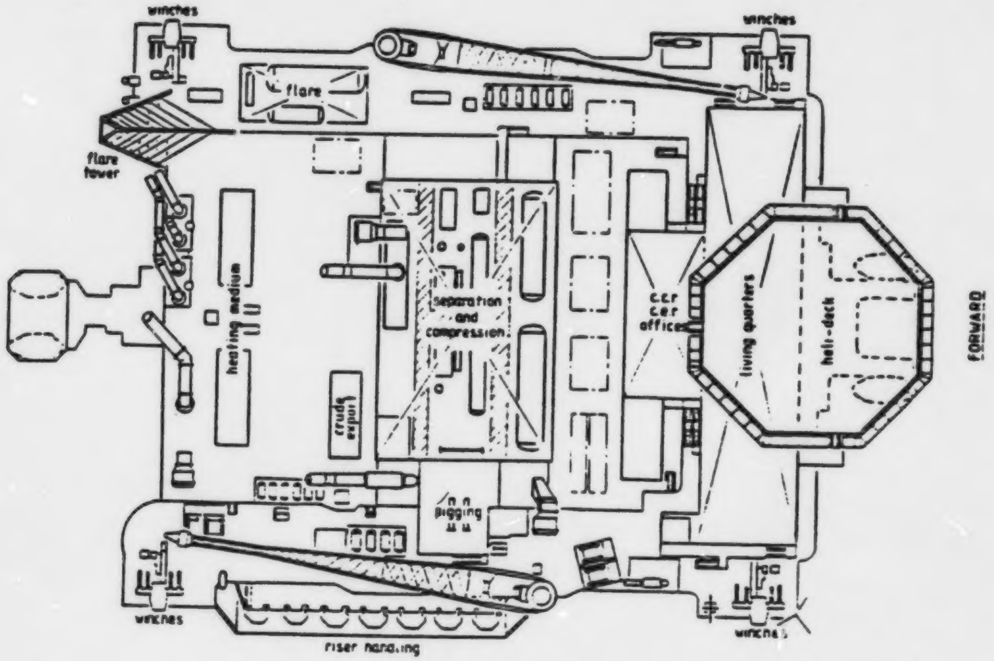

3
7
11
13
20
27
34
41
48
57
64
70
73

STARBOARD ELEVATION

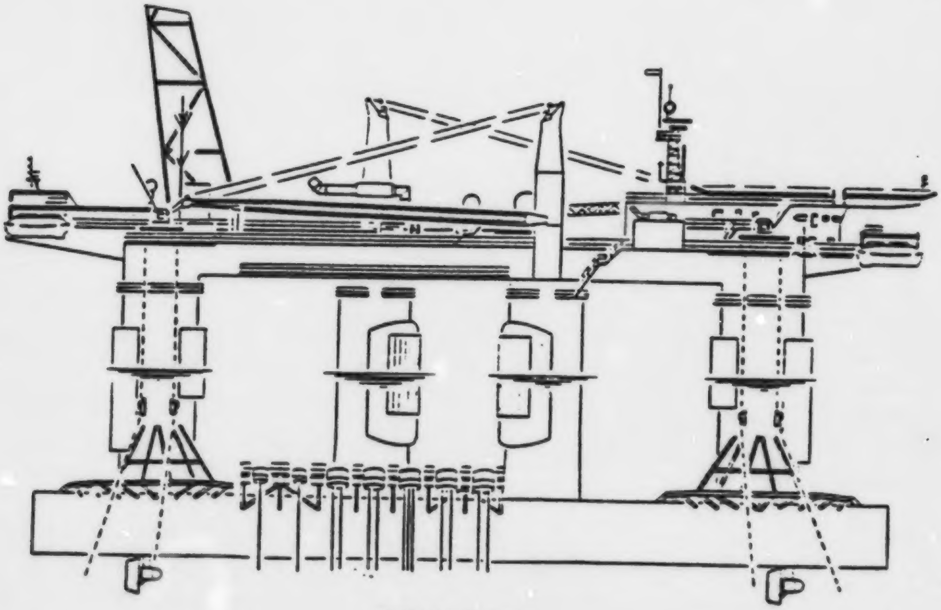

H
FORWARD
0 5 10 15 20 25 30
SCALE IN METRES

PLAN VIEW

FIG. 2


winches
flare
flare tower
winches
AFT
heating medium
crude export
separation and compression
c.c.r c.e.r office
living quarters
heli-deck
FORWARD
pigging
winches
riser handling
winches

OVERALL PLAN VIEW



STARBOARD ELEVATION

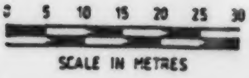

0 5 10 15 20 25 30
SCALE IN METRES

FIG. 3

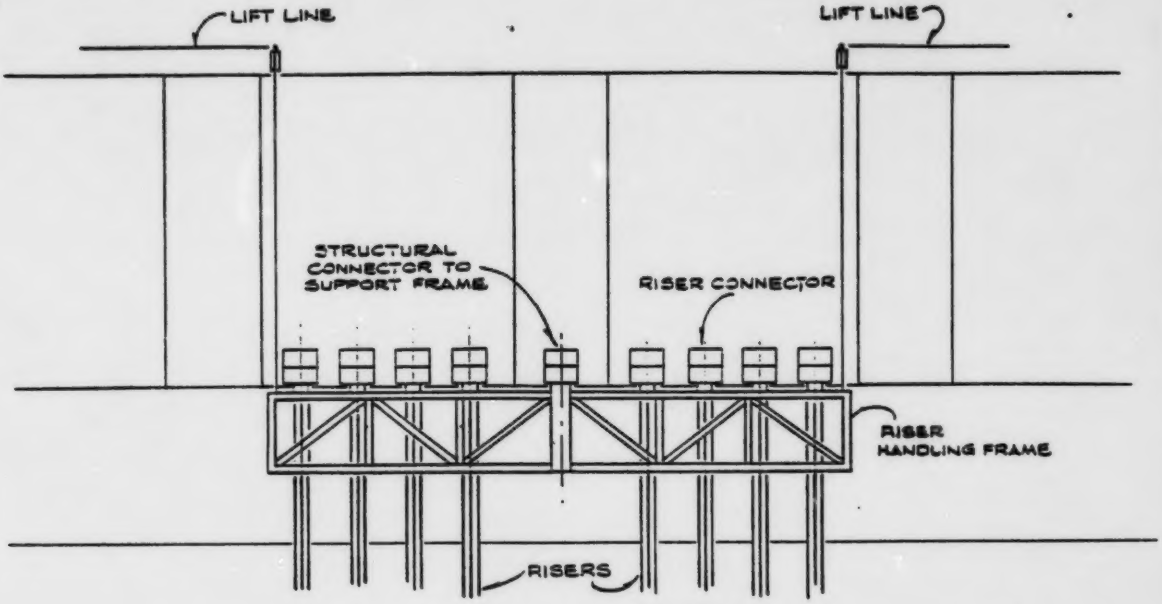

LIFT LINE
LIFT LINE
STRUCTURAL CONNECTOR TO SUPPORT FRAME
RISER CONNECTOR
RISER HANDLING FRAME
RISERS

FIG. 4

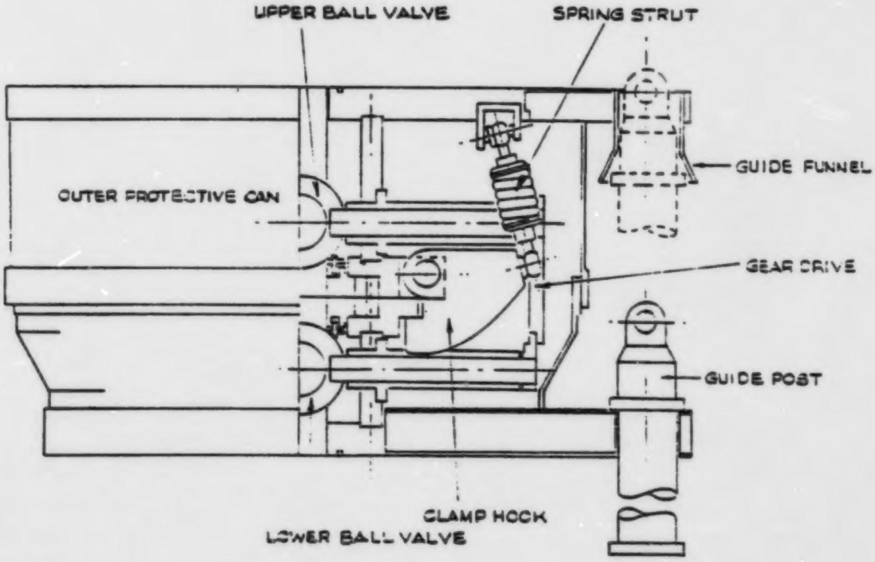
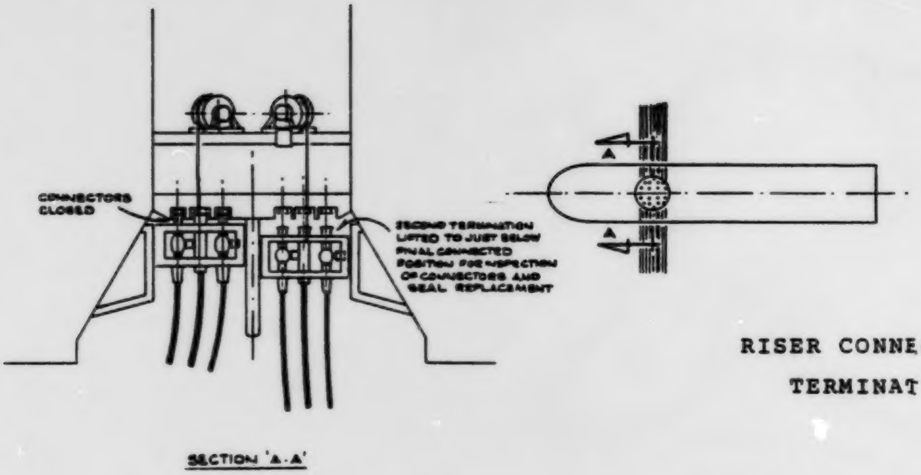
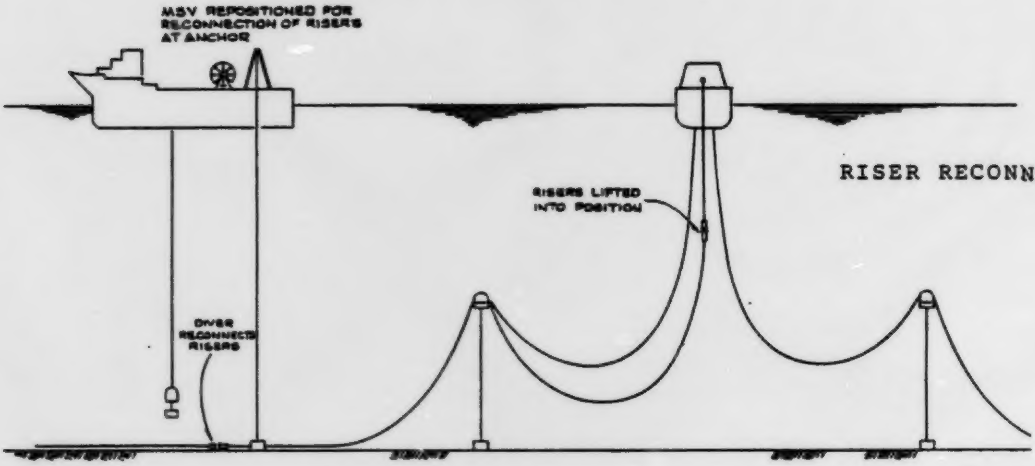

UPPER BALL VALVE
SPRING STRUT
GUIDE FUNNEL
OUTER PROTECTIVE CAN
GEAR DRIVE
GUIDE POST
CLAMP HOOK
LOWER BALL VALVE

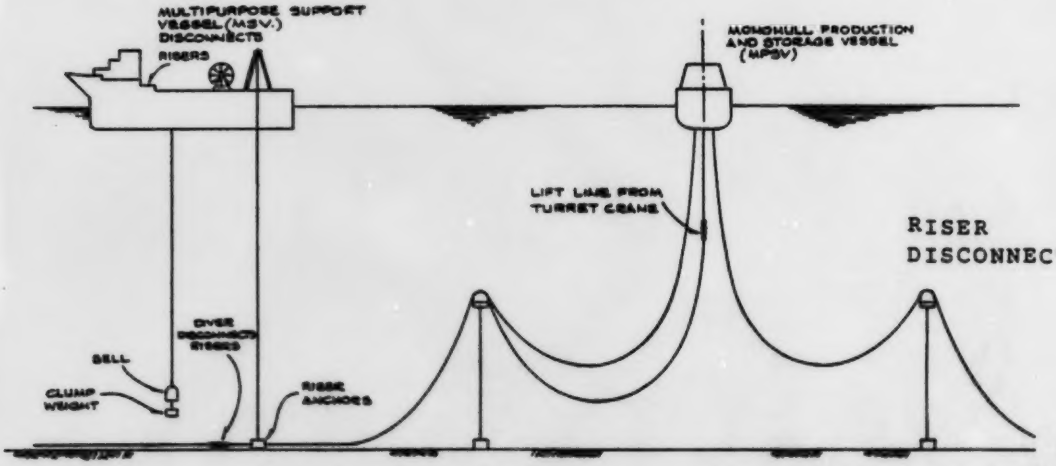
FIG. 5


CONNECTORS
CLOSED
SECOND TERMINATION
LIFTED TO JUST BELOW
FINAL CONNECTED
POSITION FOR INSPECTION
OF CONNECTORS AND
SEAL REPLACEMENT
A
A
SECTION 'A-A'

RISER CONNECTORS
TERMINATIONS


MSV REPOSITIONED FOR
RECONNECTION OF RISERS
AT ANCHOR
RISERS LIFTED
INTO POSITION
DIVER
RECONNECTS
RISERS

RISER RECONNECTION


MULTIPURPOSE SUPPORT
VESSEL (MSV.)
DISCONNECTS
RISERS
MONOHULL PRODUCTION
AND STORAGE VESSEL
(MPSV)
LIFT LINE FROM
TURRET CRANE
BELL
CLUMP
WEIGHT
DIVER
DISCONNECTS
RISERS
RISER
ANCHORS

RISER
DISCONNECTION

FIG. 6

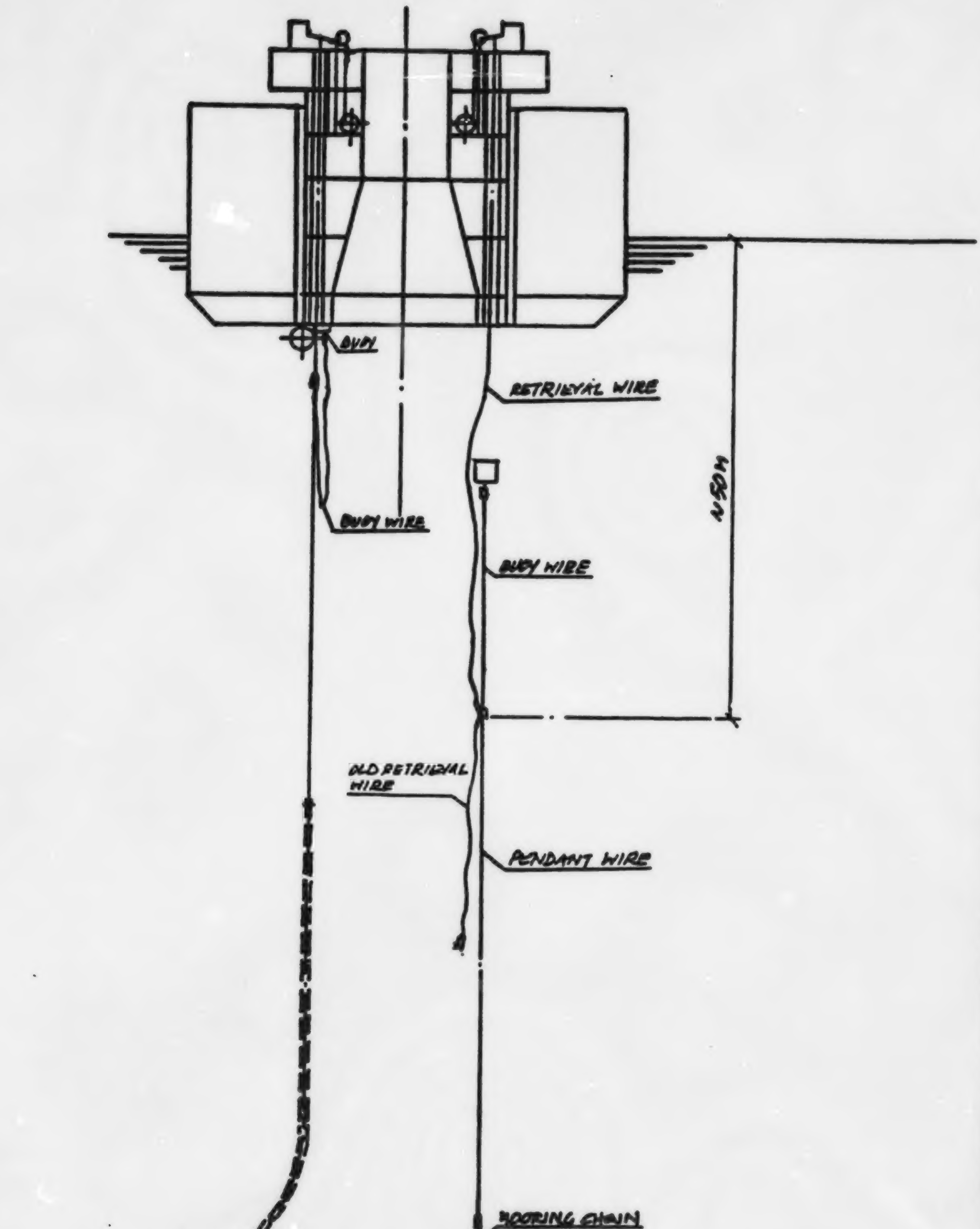

BUOY
RETRIEVAL WIRE
BUOY WIRE
BUOY WIRE
~50M
OLD RETRIEVAL WIRE
PENDANT WIRE
MOORING CHAIN

FIG. 7

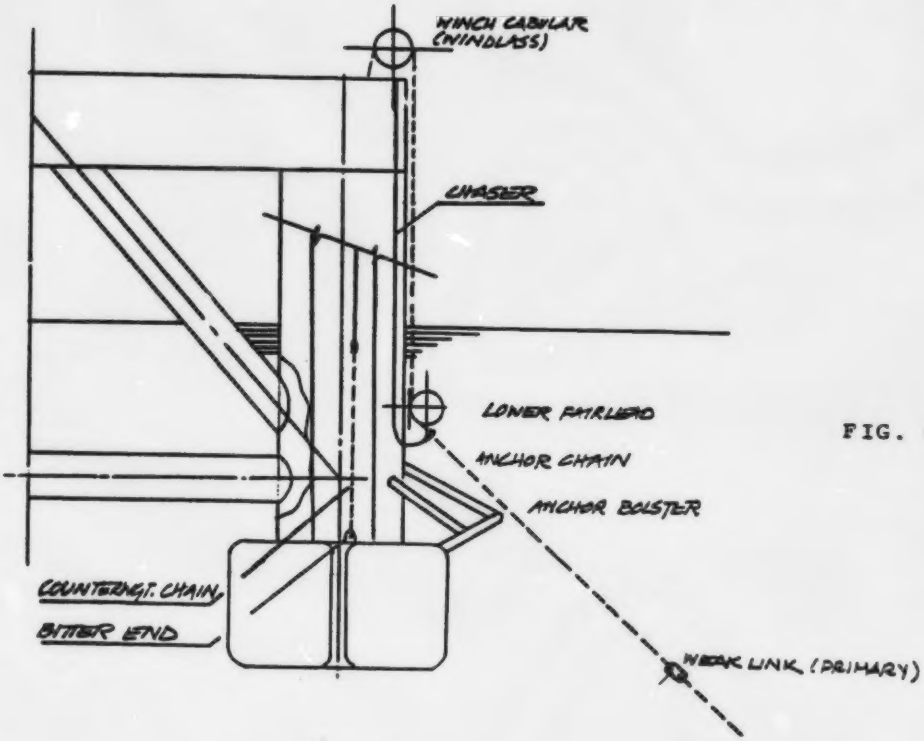

WINCH CABULAR (WINDLASS)
CHASER
LOWER FAIRLEAD
ANCHOR CHAIN
ANCHOR BOLSTER
COUNTERWGT. CHAIN
BITTER END
WEAK LINK (PRIMARY)

FIG. 8

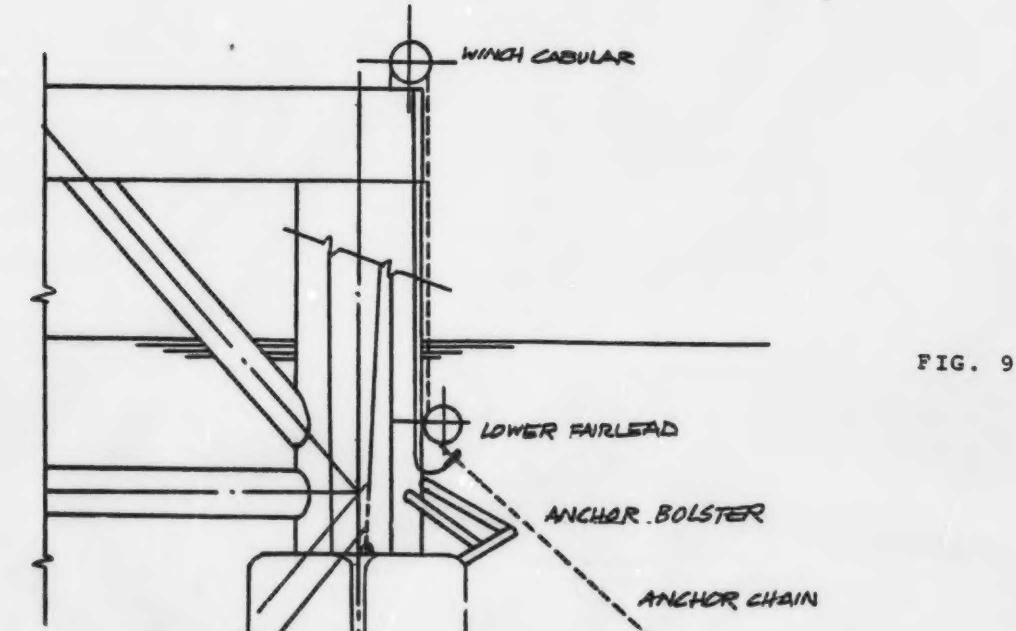
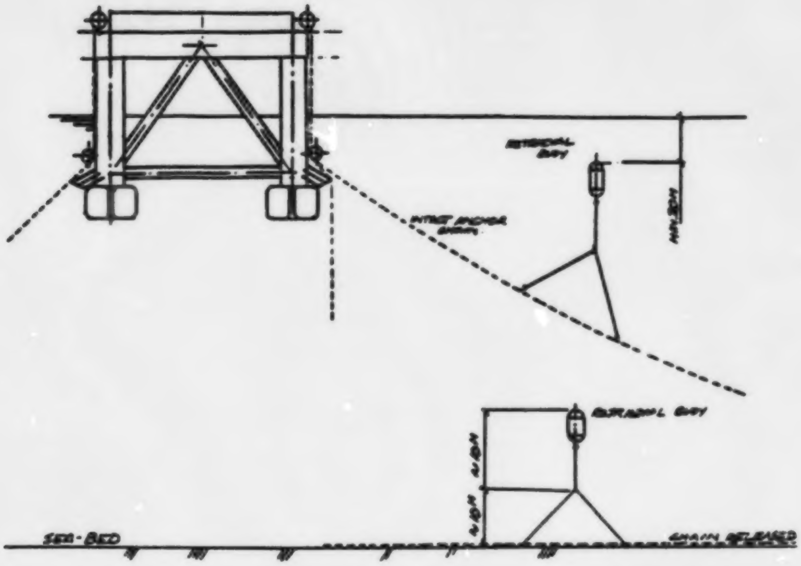
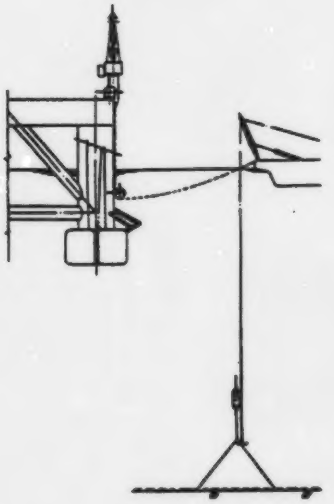

WINCH CABULAR
LOWER FAIRLEAD
ANCHOR. BOLSTER
ANCHOR CHAIN
POLYPROPOLENE ROPE
COUNTERWEIGHT CHAIN
ANCHOR RELEAS UNIT. (RAR)

FIG. 9


RETRIEVAL BUOY
INTACT ANCHOR CHAIN
RETRIEVAL BUOY
SEA-BED
CHAIN RELEASED

RETRIEVAL BUOY SYSTEM



RETRIEVING BUOY FROM SEA B

PASSING CHAIN TO ANCHOR
HANDLİNG VESSEL

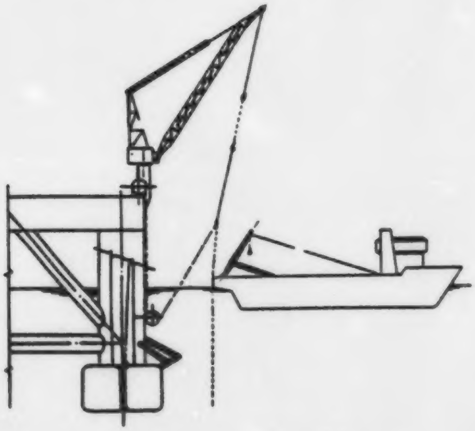
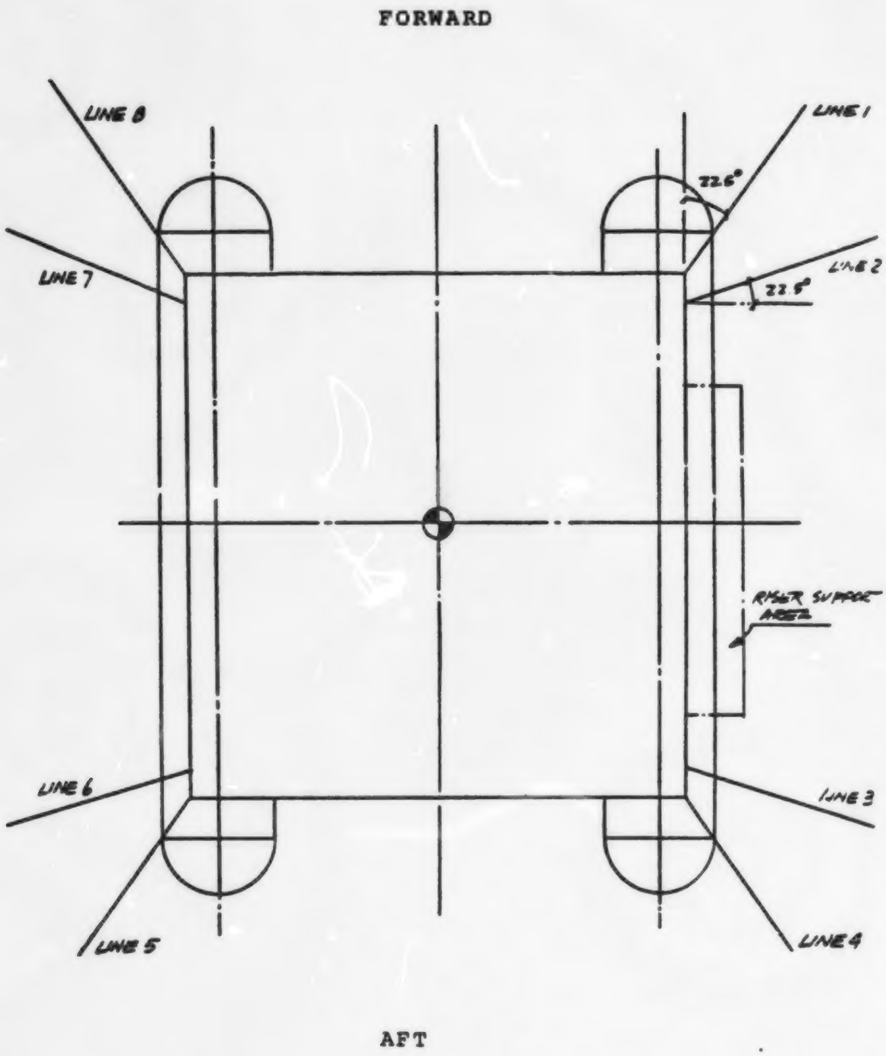


FIG.10


FORWARD
LINE 8
LINE 1
22.6°
LINE 7
LINE 2
22.5°
RISER SUPPORT AREA
LINE 6
LINE 3
LINE 5
LINE 4
AFT

ANCHOR LINE LAYDOWN PATTERN

FIG. 11

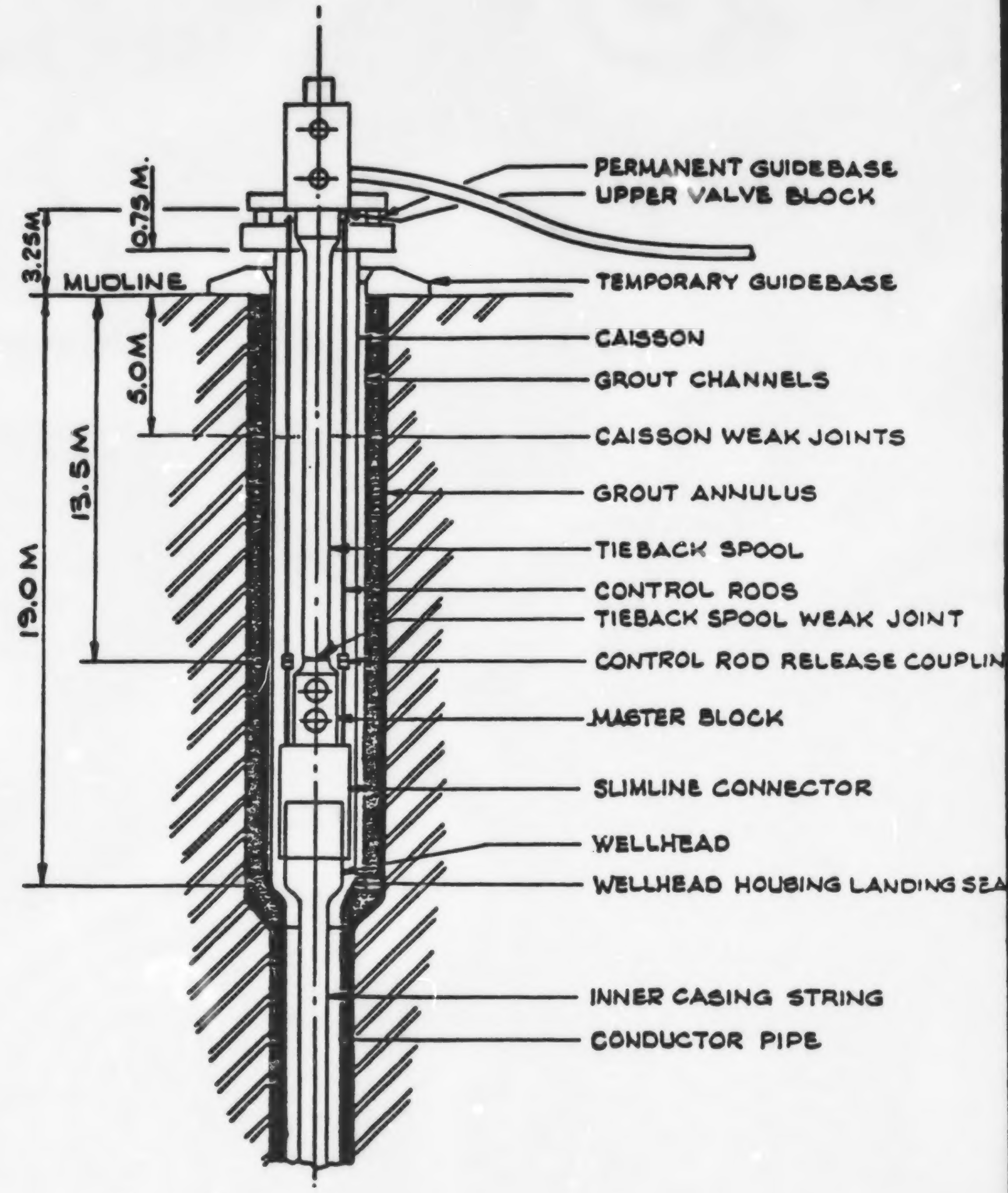
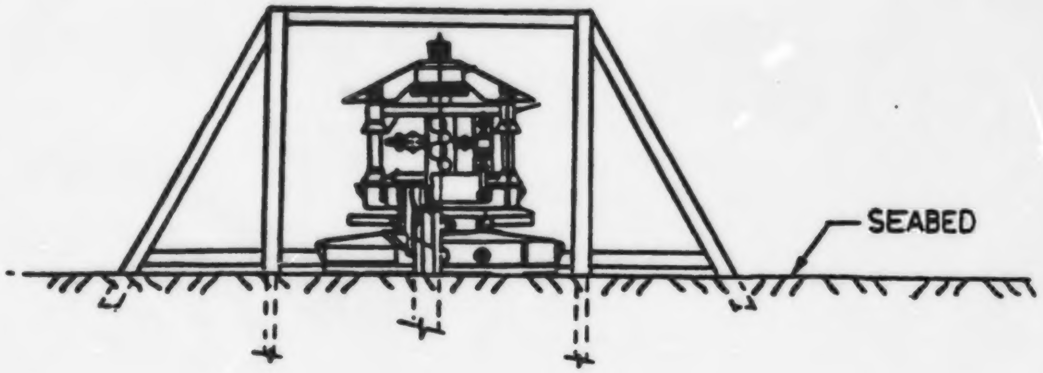
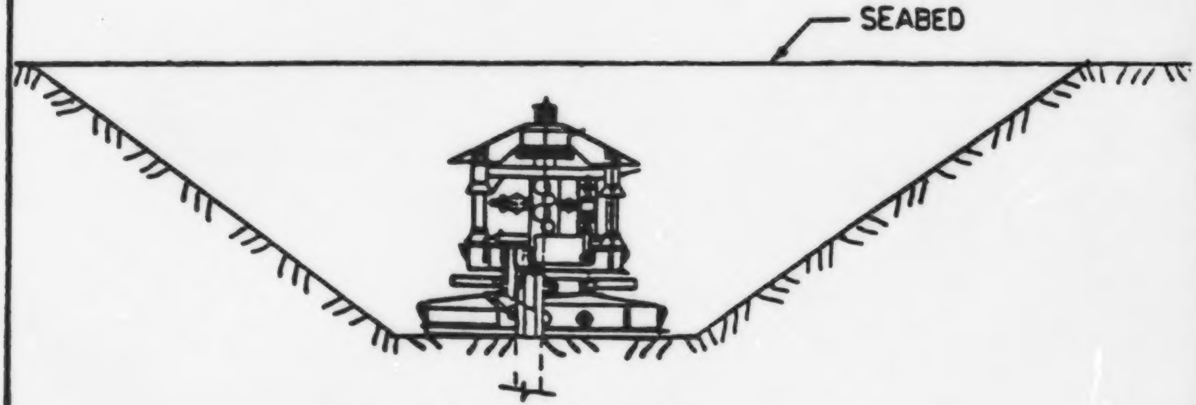

PERMANENT GUIDEBASE
UPPER VALVE BLOCK
0.75 M.
3.25M
MUDLINE
TEMPORARY GUIDEBASE
CAISSON
5.0M
GROUT CHANNELS
CAISSON WEAK JOINTS
13.5 M
GROUT ANNULUS
19.0 M
TIEBACK SPOOL
CONTROL RODS
TIEBACK SPOOL WEAK JOINT
CONTROL ROD RELEASE COUPLIN
MASTER BLOCK
SLIMLINE CONNECTOR
WELLHEAD
WELLHEAD HOUSING LANDING SEA
INNER CASING STRING
CONDUCTOR PIPE

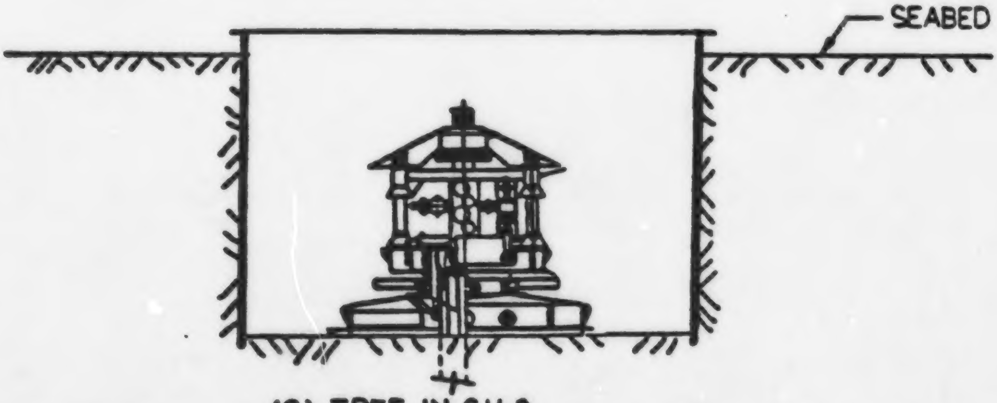
FIG. 12



(A) TREE INSIDE STRUCTURE

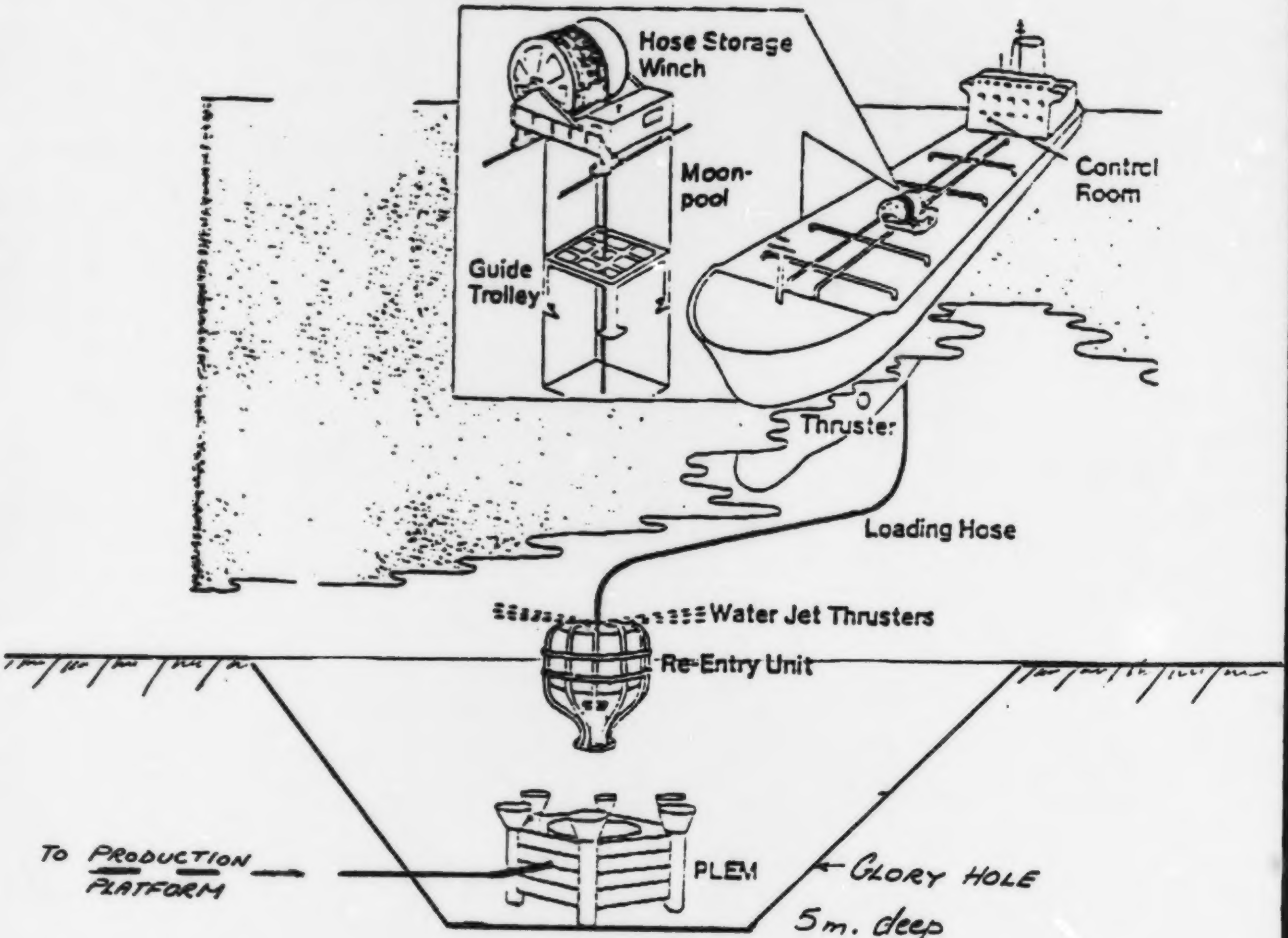


(B) TREE IN GLORYHOLE



(C) TREE IN SILO

FIG. 13


Hose Storage Winch
Moon-pool
Guide Trolley
Control Room
Thruster
Loading Hose
Water Jet Thrusters
Re-Entry Unit
TO PRODUCTION PLATFORM
PLEM
GLORY HOLE
5m. deep

OFFLOADING SYSTEM

FIG. 14

SPEAKER : **TERJE P. TELLEFSEN**

COMPANY : **A/S UGLANDS REDERI**

LOCATION : **NORWAY**

TOPIC : **CONCEPT FOR CONVERSION OF ASSOCIATED GAS TO METHANOL**

BIOGRAPHY: Mr. Tellefsen is Senior Vice-President/Offshore. He has fifteen years experience from the Norwegian offshore industry, including nine years with Norwegian Petroleum Consultants A/S on the Statfjord and Oseberg field developments. Current responsibilities involve the overall management of the entire offshore fleet consisting of twenty vessels as well as developments relating to floating production and new projects. Mr. Tellefsen holds an MBA from the Olso Institute of Business Administration.

ABSTRACT

The concept described in this paper is a completely self contained concept for developing small, isolated, offshore oil fields with associated gas, independant of well head platforms, processing centers or transport pipelines.

The main process facilities include gas/oil separation in three separation stages. The stabilized crude from the third stage is transferred to the vessel's crude storage tanks.

The gas from the second stage is mixed with the gas from the first stage, resulting in the mixed high pressure gas, which is fed to the methanol plant. Produced methanol is stored in separate tanks. The gas from the third stage is used for fuel purposes.

Export of methanol and oil to shuttle tanker is arranged at the aft end of the production vessel. The production vessel is kept in position by a thruster assisted turret mooring system.

INTRODUCTION

Both the development of isolated offshore oil fields, early production and extended well testing frequently meets with the problem of utilizing the associated gas. If no pipeline is available for gas export, the gas must either be flared, reinjected or converted to an acceptable energy form, such as electric power, liquified natural gas, or to methanol.

Long term flaring of the associated gas is not permitted by the Norwegian national energy authorities and will as well probably not be permitted in Canada. As long term gas reinjection may be detrimental to the oil recovery, the only remaining option by which permission to develop the oil field could be expected is to convert the gas to an energy form that could be stored and transported without a pipeline.

A/S Uglands Rederi in cooperation with Norwegian Petroleum Consultants A.S. have developed an techno-economical solution to this problem by converting the associated gas to fuel grade methanol. The conversion takes place in an integrated oil/gas/Methanol production plant installed on a production ship which also contains adequate storage capacity for stabilized crude as well as for methanol.

Conversion to methanol is chosen because of an anticipated large marked for methanol. The main portion of the growth potential is for auto fuel replacement, auto fuel additives or for further conversion to synthetic gasoline. An essential feature of the methanol as auto fuel additive is that the methanol is a strong octane booster in lead-free gasoline.

METHANOL MARKET AND PRICES

The traditional use of methanol is feedstock for production of other chemicals, chiefly acetic acid and formaldehyde. In the long run the expected growth in demand for these purposes can hardly justify any significant increase in the current methanol supply.

The current surplus of methanol in Europe as well as on a world wide basis is expected to last until the early 1990's, but as stated in a ICI report (J.R. Stoney, EFOA 1st annual conference, april 1986): "--- sometime after 1990 a time must come when new methanol plants will be needed to meet growing demand, or to replace some of today's plants which will then be more than 20 years old. In spite of todays short term situation, the sensible trend must be for new methanol plants to be built in remote locations where feedstock is cheap".

There is a large potential growth in demand for methanol as an extender or even a replacement for automobile gasoline, or as a feedstock for MTBE, a strong octane booster. This situation is described in a recent issue of Petroleum Times Price Report, August 1, 1988.

Quote:

"Fast growing fuel uses for methanol are already causing spot shortage and will keep markets tight through to 1995. Behind the rising demand for methanol, currently 7 per cent a year, is the increasing use of Methyl Tertiary Butyl Ether (MTBE) as a high octane blending component.

By the end of 1988, legislation in many parts of the world will allow up to 15 per cent of MTBE by volume in gasoline as lead phase out is implemented. This means that MTBE can comprise up to 10 per cent of the total gasoline pool, a large potential market. The use of MTBE accounts for 15 per cent of methanol consumption and according to Saudi Basic Industries (SABIC), growth is expected to average 16 per cent a year up to 2000".

Methanol, however, may eventually eclipse MTBE as a high octane blending component providing refiners can improve their distribution system by eliminating water from gasoline. Ultimately pure methanol may be used as a primary fuel. It is clean burning with low emission properties and SABIC predict that it will replace conventional hydrocarbon fuels in the next century." Unquote.

With respect to the sales price for methanol, there is an established marked and internationally quoted prices for chemical grade methanol, but not for fuel grade. A future price for fuel grade methanol will certainly be established, and related to the prices for crude oil and gasoline. The actual price for fuel grade methanol to the consumer may also be affected by taxation policies. Most likely that price will be lower than the price for chemical grade methanol.

The price for chemical grade methanol in Europe is depending on whether it is imported to EEC or not. The price trend over the last 3 years has been a drastic fall from USA 130 - 140 per tonne in the second half of 1985, to USD 70 - 80 per tonne late 1986, and then a steady trend upwards to about USD 180 - 190 per tonne in June 1988. In the US the increase has been much higher; in June 1988 the US prices were well in excess of USD 250 per tonne. Since then the methanol prices have fluctuated above USD 160 per tonne.

For the economic analysis we have assumed a sales price delivered European port, of USD 165 per tonne of our fuel grade methanol quality. An additional evaluation is based on an assumed price of USD 135 per tonne.

It is our considered opinion that offshore methanol will be on the marked in the comparatively near future due to:

- Pollution policies, particularly in Europe and North America will favour the use of methanol as an octane booster, gasoline extender or replacement.
- Offshore accociated gas supplied to the offshore methanol plants practically free of charge will make offshore methanol considerably cheaper than onshore methanol where the producers will pay continental gas prices for the feedstock.

Even if project preparations start immediately (May 1989) no new methanol plant can be expected to go on stream until mid 1992 at the very best, by which time a demand for new methanol capacity might be considerable.

FIELD SITUATION AND DESIGN BASIS

A large portion of undeveloped offshore oil reserves in the North Sea and elsewhere are contained in small fields. New technology will be required to profitable exploit these smaller accumulations.

This new technology will include subsea wells of well head platforms, in combination with low-manned/remotely controlled light weight production-platforms or floating production systems.

Smaller accumulations close to an existing field centre can most probably be developed by satellite wells and direct well stream transfer flowlines. Accumulations at some distance to an existing field center will preferably be developed by low-manned or remotely controlled platforms or floaters with the minimum required process facility to allow for pipeline export to the centre.

By these means, the field center may be fully utilized also after it's own peak production has been passed.

However, due to the short expected production life of small oil-accumulations at greater distances from existing installations the installation of pipelines for export may tend to be uneconomical compared to shuttle tanker export.

For oil fields where export of the associated gas by pipeline is not applicable, production of methanol will offer an attractive solution to the problem of utilizing the gas.

Production ships lend themselves very well to developing small isolated fields where associated gas is to be converted to methanol. The advantages of production ships are their large capacity to carry the required topside facilities, their ability to store produced oil and methanol and that they can be equipped with an intergrated low cost export station.

The assumed field for this study produces 60 000 barrels per day through six wells with a gas-oil-ratio of 100 Sm^3/Sm^3, with North Sea weather conditions and sea state. The water injection facilities for 90.000 barrels per day through four subsea wells are also included.

The subsea well configuration includes six well slot template and four single satellite wells. The template is connected to the ship by two flexible risers. The floater is a ship, in shape similar to the larger shuttle tankers operating in the North Sea, tonnage UMS gross, about 87.000, overall length 268.5 meters and breadth molded 46.20 meters, with combined dynamic position and anchor mooring.

The ship contains full facilities for stabilizing the produced crude in a three stage separation process, all required support and utility systems, as well as a plant for converting the (abt.) 900,000 Sm^3 per day of associated gas to about 900 tonnes per day of fuel grade methanol.

The ships hull contains separate storage of stabilized crude and of methanol corresponding to ten days production. The products will be brought ashore by a dedicated shuttle tanker.

The production ship will thus be suitable both for early production and extended well testing, in addition to regular field development. However, for well testing purposes the production ship will have to be used in conjunction with a drilling semi since the production ship itself has no workover facilities.

OVERALL GAS BALANCE

Three gas sources are available for use on the floater:

- gas from the first stage separation	633,000 Sm^3/d
- gas from the second stage separation	137,000 "
- gas from the third stage separation	122,000 "
TOTAL GAS AVAILABLE	892,000 Sm^3/d

Main gas consumers:

- Methanol plant feedstock and fuel	729,000 Sm^3/d
- Gas turbine fuel gas	82,000 "
- Steam boiler fuel gas	21,000 "
TOTAL GAS CONSUMPTION	832,000 Sm^3/d

Excess gas available for miscellaneous users or for additional methanol production 60,000 Sm^3/d

In completely calm weather where the trusters are not used, an additional gas availability will be 40,000 Sm^3/d

This 100,000 Sm^3/d of gas could represent 100 tonnes of methanol per day. This excess capacity is built into the methanol plant giving a maximum capacity of 960 tonnes per day. The design capacity would be 860 tonnes per day. This assumes an oil production of 60,000 barrels per day and a gas-oil-ratio of 100 Sm^3/Sm^3.

OIL AND GAS PROCESS

General

The objective of the oil and gas processing facilities is to receive the unseparated wellstream to stabilize the crude to storage and offshore loading specifications, and to separate the associated gas and deliver it as methanol plant feedstock at the required pressure.

For the liquid phase this will mean stabilizing it through heat treatment to specifications compatible with intermediate storage onboard the processing vessel and later transport in shuttle tankers to shore terminals. (TVP = 0.85 bar at 38°C.)

Recompression pressure is selected to suit both the methanol process requirements and fuelling of the gas turbine drivers. All flashgas can thus be utilized either for methanol production or for heating, and propulsion and main power generation purposes.

Process Description

The unprocessed fluid from the reservoir enters the first stage separator which is controlled at a pressure of 67 bara. Liquid from the first stage separator enters 2nd stage separator at 25 bara and 55°C. Water is removed in the separation stages and sent to the water treatment system. The oil stream is heated by steam in the crude heater before entering the 3rd stage separator where the crude is stabilised at 78°C and 1.5 bara. The water content is reduced in the electrostatic coalescer to meet sales specifications. The oil from the coalescer is cooled before metering and transport to storage.

Gas released from the three separator stages is cooled to 32 degrees C before entering a scrubber for maximizing oil yield. The first and second stage gas is fed to the methanol plant, as fuel and feedgas, at 25 bara, while the third stage gas is mainly used for fuel purposes outside the methanol plant.

Sparing Philosophy

All major heat exchanger and pump duties are split on 3 x 50% units, where 2 units are normally in operation. Separator vessels are not spared. 2 x 100% capacity is installed for the recompression process, since the production of fuel is important for maintaining both oil and methanol production.

For shorter periods, however, it is possible to operate both the methanol and the oil process by draining fuel for the boilers from the 2nd stage separator, or simply by firing with diesel or produced oil.

METHANOL PROCESS

The methanol plant has been designed by Haldor Topsøe A/S, Copenhagen.

Methanol is synthesized by reaction of hydrogen and carbon oxides in accordance with the following reaction schemes:

$$CO + 2H_2 \longleftrightarrow CH_3OH + \text{heat}$$

$$CO_2 + 3H_2 \longleftrightarrow CH_3OH + H_2O + \text{heat}$$

The methanol conversion is favoured by high pressure and low temperature, whereas the rate of reaction is favoured by high temperature and requires the presence of a catalyst.

The economic optimum conditions chosen for the Haldor Topsøe process are 70 barg and slightly less than 300°C.

The synthesis takes place in two reactors filled with a copper

containing catalyst (Topsøe type MK 101).
The synthesis takes place in two reactors filled with a copper containing catalyst (Topsøe type MK 101).

The synthesis gas is compressed to reaction pressure and is in a feed/effluent exchanger heated to reaction temperature. The remaining part of the considerable amount of heat liberated is used for preheating of boiler feed water in a heat exchanger between the converters. Methanol synthesized is - together with water - condensed in a water cooler, and unconverted gas is recycled to the two converters.

The synthesis gas for the methanol reaction is made by steam reforming of associated gas. By steam reforming hydrocarbons are in the presence of steam converted to a mixture of H_2, CO, CO_2, and CH_4. The reaction takes place in a tubular reformer. A number of high alloy Cr-Ni steel tubes are mounted vertically inside a furnace chamber. The tubes are filled with a nickel containing catalyst named R-67-7H. The associated gas/steam mixture is passed downwards through the tubes and the necessary heat is furnished by firing of gas in a number of burners located in the side wall of the furnace chamber.

The reformer is provided with a flue gas waste heat section, where sensible heat is recovered by preheating of gas, water, and combustion air. The reforming takes place in the temperature range 500-850°C at a pressure of 20 barg.

The reformer gas mixture is cooled in a number of heat exchangers whereby steam is raised.

The raw methanol/water mixture from the synthesis contains some byproducts among which are dimenthylether and propanol. These impurities together with water are removed in a single column distillation unit. The heat necessary for the distillation is provided as waste heat from elsewhere in the methanol plant.

By varying the number of columns in the distillation unit, all methanol specifications can be obtained.

The methanol unit is autonomous with respect to steam, except during start-up.

SHIP HULL DESIGN

The purpose of the floater is

- To provide carrying capacity and deck area, for a process plant of 60 000 barrel/day of crude oil and 860 tonnes/day of methanol.
- To provide sufficient storage capacity to allow for continuous production.
- To accommodate position keeping system and auxiliary functions such as power generation, living quarter and export station to shuttle tankers.

The criteria for determining the storage capacity of the production ship is the cycle of a shuttle tanker's round trip and the connection time including wait-on-weather.

Expected wait-on-weather for designing the storage capacity is estimated by simulation.

Offshore loading is a weather sensitive operation and requires moderate sea state. Without adequate storage capacity, the production might be subject to shutdown during periods with high sea state. The production vessel's storage capacity should be adequate for continuous production during the shuttle tanker's roundtrip, including wait-on-weather at the field. The storage capacity corresponds to ten days full production.

For typical North Sea wave climate and a theoretical shuttle tanker roundtrip of 6,5 days, (including steaming, loading and unloading) production shut downs due to lack of storage, will take place less than once in a 5 year period.

Based on required storage volume, the main parameters of the vessel were estimated by using a set of empirical weight, volume and area relations derived from earlier topside and floater projects. Based on main parameters the hull-form was developed and Hydrostatics. tankvolumes, freeboard, light ship weight, loading conditions and stability was calculated.

Principal dimensions:

Length overall	268.50 m
Length between per.	252.00 m
Breadth moulded	46.20 m
Depth to upper deck	21.00 m
Freeboard draught	16.24 m
Design draught	15.00 m

Tonnage UMS gross about 87.000.

SHIPS ARRANGEMENT AND WEIGHT SUMMARY

Ship Arrangement

The general arrangement of the production ship is shown on Figure 1. Except for the turret, the internal arrangement of the vessel is more or less similar to modern shuttle tankers.

The vessel is arranged with double bottom, one longitudinal bulkhead and double sides in the cargo area. The longitudinal centre line bulkhead and all transverse bulkheads are of corrugated type.

In the vessel's cargo area are located 14 crude oil storage tanks and 3 methanol storage tanks.

One pump-room for Crude oil and methanol is located aft of cargo area. Ballast pump-room is located forward of cargo area.

Segregated water ballast is arranged in aft peak tank, wingtanks in thruster rooms, double bottom tanks, wing tanks in cargo area, and in fore peak tank.

For this concept, a thruster assisted turret mooring system is chosen as the primary means of station keeping.

Electrical power is generated by three dual fuel gas turbine driven generators. Generators are arranged in deck house aft.

Accommodation for 80 persons, control rooms and wheel house are arranged in deck house forward.

Helideck is arranged on top of deck house.

Lifesaving comprises 6 enclosed lifeboats and 1 pickup boat.

Equipment and system for methanol production and oil/gas separation are arranged in modules on tank-deck.

Starting forward there is one module for oil/gas separation, three modules for methanol process equipment and one module for cooling water equipment.

A ground flare is arranged on aft deck.

Three cranes are arranged on deck in connection with the process-plant, lay-down area and helideck.

Arrangement for export to shuttle tanker is arranged on the floater's stern by flexible export lines for both oil and methanol.

Weight Estimate Summary

Weitht Estimates are based on volumetric factoring using data collated from recent offshore projects and weights provided by different disciplines.

WEIGHT SUMMARY OF PROCESS UNITS, - TONNES

	STRUCTURAL STEEL	EQUIPMENT AND BULKS	TOTAL
GAS REFORMING MODULE MP1	216	1544	1760
METHANOL MODULE MP2	826	910	1736
METHANOL MODULE MP3	826	1173	1999
OIL SEPARATION MODULE D41	449	621	1070
COOLING WATER MODULE D42	323	268	591
MODULE SHOES AND DECK REINFORCEMENT	1090	10	1100
TOTAL WEIGHT	3700	4526	8256

MOTION CHARACTERISTICS AND POSITION KEEPING

Motion Characteristics

Generally, the motions are very satisfactory. For small waves with periods up to 11 s., the heave motions are slightly higher than for a typical semi-submersible, while for wave periods between 11 - 15 s., the ship is significantly better. The pitch motions are better than for a typical semi-submersible for wave periods up to 12 s.

The methanol process plant is the most critical part on the vessel with respect to ship motions. Excessive transverse or longitudinal accelerations will terminate the methanol production.

Transverse and longitudinal accelerations at the top of the distillation tower approximately 38 meters above deck, have been calculated. Wave direction beam sea and 30 degrees off bow was assumed. The accelatation versus probability is shown on Figure.

An estimate of the production regularity is found directly from the probability function of the significant waveheight assuming restart of process at once after the seastate is below the critical wave height.

For wave direction 30° offbow a maximum acceleration of 0.5 m/s^2, occurs in approximately 8 meters significant waveheight from bow. The corresponding average process regularity will be approximately 99 percent based on wave statistics.

Accelerations due to beam sea have also been calculated. The wind generated sea will normally be directed towards the bow, but beam sea may occur due to swell.

For the actual metacentric height (GM) of 6,8 m and a regular beam sea (swell) with a wave height equal to 6 meters and period equal to the ship's natural period of roll, the acceleration is calculated to 1,7 m/s^2, which is much higher than for any head sea. Beam swell will probably be the governing parameter for the methanol process regularity. This seastate may occur when combination of beam swell and wind generated head sea is acting on the vessel. For example, a seastate with 9 meters significant wave height can in some cases be a combination of 5 meter head sea and 4 meter beam (swell).

Accelerations based on the minimum allowable GM equal 4,4 meters have also been plotted. This indicates that by rearranging the ballast arrangement in order to reduce the GM the critical swell height could be increased to what is unlikely to occur.

An acceleration of approximately 1.7 m/s^2 is used as a design criteria for the methanol process plant.

The gas phase processes are not very sensitive to local accelerations. Rotating equipment will be oriented and its bearings so designed as to counter any gyro-effects during motion. Emphasis will be put on the design of the units where the liquid phase processes take place; e.g. separators will be equipped with baffles and specially designed level controllers, the distillation columns will be split in two sections and given an increased total length and given carefylly chosen internals. The reformer furnace refractory, usually bricks, will be of a flexible, fibrous, material.

Position Keeping

Position keeping is accomplished by a thruster assisted turret mooring system. The thruster system consists of two main propellers and 5 thrusters, three forward and two aft.

The main propellers and thrusters will be used for heading control and for reducing the offset and mooring line tensioning in adverse weather. The turret has a passive mooring system, with 10 anchor lines terminated in chain stoppers at the turret.

Design criteria for the main propeller and thruster system:

1. The available net thrust force from the main propellers must be able to counteract the surge forces in a 100-year storm condition from the bow.

2. The side thrust force from thrusters must be able to counteract the turning moment when wind and current are acting 30 degrees off the bow and the waves directly on bow for weather conditions corresponding to a 'Beaufort 8' storm condition.

The main propeller system consists of two controllable pitch propellers, each of abt. 8.000 kW.

Side thrusters of azimuth propeller type are chosen to assure thruster capacity in severe weather condition where tunnel thrusters are liable to air suction.

Each of the 5 thrusters has a capacity of abt. 2.000 kW.

The turret is arranged for a passive mooring system. The anchor chain terminates in chain stoppers arranged outside the turret shaft.

The turret shaft is a cylindrical structure located vertically and concentric in the ship's moonpool. A turret house is placed above the moonpool.

The turret is supported by a lower and an upper bearing assembly. The bearings are of sliding type (Atlas Glideflex).

The fair-leads are located close to the lower bearing level at the bottom end of the turret shaft.

The wellstream is conveyed from the subsea manifolds to the ship via two flexible flowlines. In addition, there is one service bundle line and one water injection line.

The top of the four risers are connected to Coflexip connectors that are located at the bottom of the turret shaft.

Four wire winches for lowering the connectors, when changing risers, are located inside the turret house.

The swivel for passing the wellstream, waterinjection and service lines from the fixed turret to the rotating floater is also arranged inside the turret house.

Two chain windlasses are located on top of turret house in connection with two combined wire and chain fairleads.

In case of a need for chain tension adjustment, this is done by reconnecting a chain length to the anchor line in question, tightening with the chain windlasses to take the load off the chain stopper, releasing the chain stopper and adjusting the pretension to correct value before reactivating the chain stopper.

Two wire winches are arranged on top of turret house for pull-in purposes when installing the mooring lines.

Mooring equipment is of Pusnes type.

SAFETY DESIGN AND EVALUATION

The safety work carried out during this project covers the safety design as well as a preliminary conceptual safety evaluation.

In addition, DnV were engaged to carry out a feasibility evaluation of placing the methanol plant in gas hazardous areas on the tank deck.

From the DnV report of May 10, 1988 we quote one of the central paragraphs:

"The installation is found to be feasible from a safety point of view based on Det norske Veritas' Rules and Norwegian Petroleum Directorate Regulations (NPD) provided that the requirements tc hazardous areas are complied with."

The vessel will also meet relevant criteria put forward by Norwegian Maritime Directorate. The production plant and storage have been so designed that the DnV class notations "Oil Production and Storage Vessel (N)" can be attained for production mode in moored position, and "Oil Carrier" for transportation mode.

The authority requirements considered for the concept are the relevant requirements of the following regulations:

National Authorities:

- The Norwegian Maritime Directorate (NMD) regarding "Drilling Vessel" and "Tanker for Oil",
- The Norwegian Petroleum Directorate (NPD) regarding "Production Facilities".

International Authorties:

- International Convention for the Safety of Life at Sea, 1974 (SOLAS), with Protocol of 1978.
- International Convention on Load Lines, 1966.
- International Convention of Pollution from Ships, 1973, with Protocol of 1978.

Safety Design

Some important aspects of safety and associated design features considered are discussed below:

Fires and explosions have been identified as the main hazards. Potential ignition sources are designed as enclosed units and/or located with this in mind, especially for the high temperature steam reformer.

The process and methanol modules have natural ventilation, thus reducing the possibility for ignitable concentrations and high explosion pressures.

The two main escapeways leading fore/aft are enclosed, thus providing both weather and fire explosion protection.

Firewalls comply with class requirements and the methanol plant and process module are separated by a H-0 wall, which has also been specified for the front side of the process module. The deck house wall facing the process area is rated H-120.

Disposal of excess gas is through the ground flare, and flare radiation is well within relevant limits.

ECONOMIC ANALYSIS

Economic evaluations have been carried out for the two basic modes of operation in which the production vessel can be involved.

These two modes are: "Early Production" and "Permanent Field Development". Early production is assumed over a three year period. Permanent field developmenmt is assumed for a field with 60,000 b/d plateau production, total oil production of 160 mill bbls over the 10 years production period.

The cases are based on reasonable assumptions for financing and servicing of capital together with anticipated operation cost.

As discussed elsewhere the floater may be configured for a number of different concepts. However, alterations to capacities and configurations will have limited effect on the overall analysis.

Economic Analysis "Early Production" - Vessel only

COST SUMMARY - VESSEL ONLY		
From the cost summary above the following key figures are used:		
Oil and gas plant Methanol plant Common services	USD	277 mill
Vessel	USD	161 mill
Total	USD	438 mill

This estimate contains the total costs for engineering design, project and construction management, manufacture, procurement, transportation, fabrication/construction, hook-up, marine operations, and completion/-commissioning.

BASE CASE ASSUMPTIONS OR EARLY PRODUCTION	
Oil production	60,000 barrels/day
Gas-oil-ratio	100 Sm^3/Sm^3
Methanol production	900 tonnes/day
Operating days per year	320 days
Duration	3 years
Sales price methanol	165 USD/t
Feedstock gas price	nil

Vessel operation cost is estimated to USD 15 mill/year. Included in the estimate is a crew of 50 onboard, insurance, repair/maintenance and shore support.

Not included in the operation cost is helicopter transport and other operators cost.

EARLY PRODUCTION - COST PER BARREL, FOR PRODUCTION VSL ONLY	
Oil production only - no methanol plant	USD 4.80 per bbl
Oil prod. cost, incl. methanol plant & revenue	USD 4.40 per bbl
Break-even salges price for methanol	USD 140 per t.

The "Oil production cost including methanol plant", shows oil production cost with the contribution of the methanol plant on the overall economy. Todays marked price of methanol gives a positive contribution as shown.

Economic Analysis "Permanent Field Development"

COST SUMMARY "TOTAL FIELD DEVELOPMENT"	
From the cost summary the following key values are used:	
Vessel total	USD 431 mill
Subsea wells	USD 353 mill
GRAND TOTAL	USD 791 mill

BASE CASE ASSYNOTUIBS FOR "TOTAL FIELD
"PERMANENT FIELD DEVELOPMENT"

Oil production	60,000 barrels per day
Gas-oil-ratio	100 Sm^3/Sm^3
Methanol production	860 tonnes/day
Operating days per year	320 days
Production time	10 years
Accumulated production over project lifetime	160 barrels
Sales price methanol	165 USD/tonne
Feedstock gas price	nil

Vessel operation cost is as for part A, estimated to USD 15 mill/year. Subsea well maintenance cost is estimated to USD 13 mill/year. Shuttle tanker cost is estimated to USD 11 mill/year.

PERMANENT FIELD DEVELOPMENT COST PER BARREL INCLUDING
PRODUCTION VESSEL, SUBSEA WELLS, INSTALLATION.
SHUTTLE TANKER ETC.

Oil production only - no methanol plant	USD 9.70 per bbl
Oil prod. cost, incl. methanol plant & revenue	USD 8.70 per bbl
Break-even sales price for methanol	USD 95 per tonne

The Oil production cost includes methanol, shows oil production cost with the contribution of the methanol plant on the overall economy. Todays marked price of methanol gives a positive contribution as shown.

Economic Analysis of Methanol Production Alone

Annual capital requirement for methanol plant alone as an incremental investment in the "Total Field Development" concept, is estimated to USD 22 mill with incremental operations cost being USD 4 mill giving total annual cost of USD 26 mill.

Annual methanol production is estimated to 288,000 tonnes.

Assumed sales price for fuel methanol is USD 165 per tonne.

Annual methanol revenue on plateau production, based on current market price is therefore USD 47.5 mill. Current market price of methanol gives an IRR on the methanol plant better then 25%.

Break-even situation on methanol plant occurs on a methanol price of USD 95 per tonne with an annual production of 288,000 tonnes for the "Permanent Field Development" concept.

Conclusions

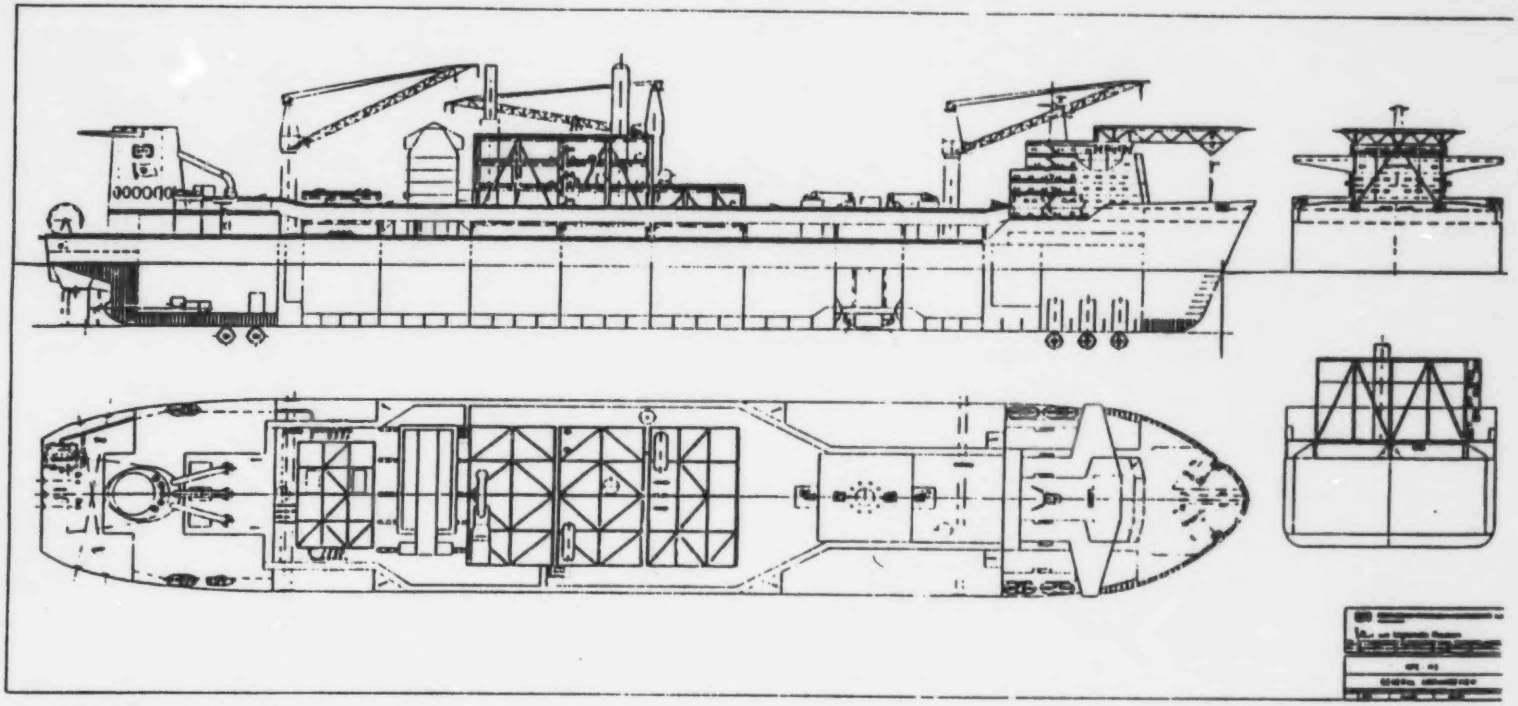
Based on the stated assumptions, for the Permanent Field Development, the conclusion is that the entire field installation will be commercial for a crude oil price of USD 9.70 per barrel if the methanol plant is not included (and the gas is flared), - and USD 8.70 per barrel if the gas is converted to methanol and sold for USD 165 per tonne. At a methanol price of USD 95 per tonne the two sections, with and without methanol, become equally attractive.

An analysis of the methanol plant as an incremental investment, shows that the assumed methanol sales price of USD 165 per tonne yields an internal Rate of Return in excess of 25%.

In order to test the effect of making less favourable assumptions for two of the main variables, the methanol price was reduced to USD 135 per tonne, and the assumed operating cost was increased by 50%.

The result is that the entire installation will be commercial for crude prices of USD 10.2 and USD 9.7 respectively for the "No methanol" and "Methanol" cases, and that the break-even price for methanol becomes USD 105 per tonne.

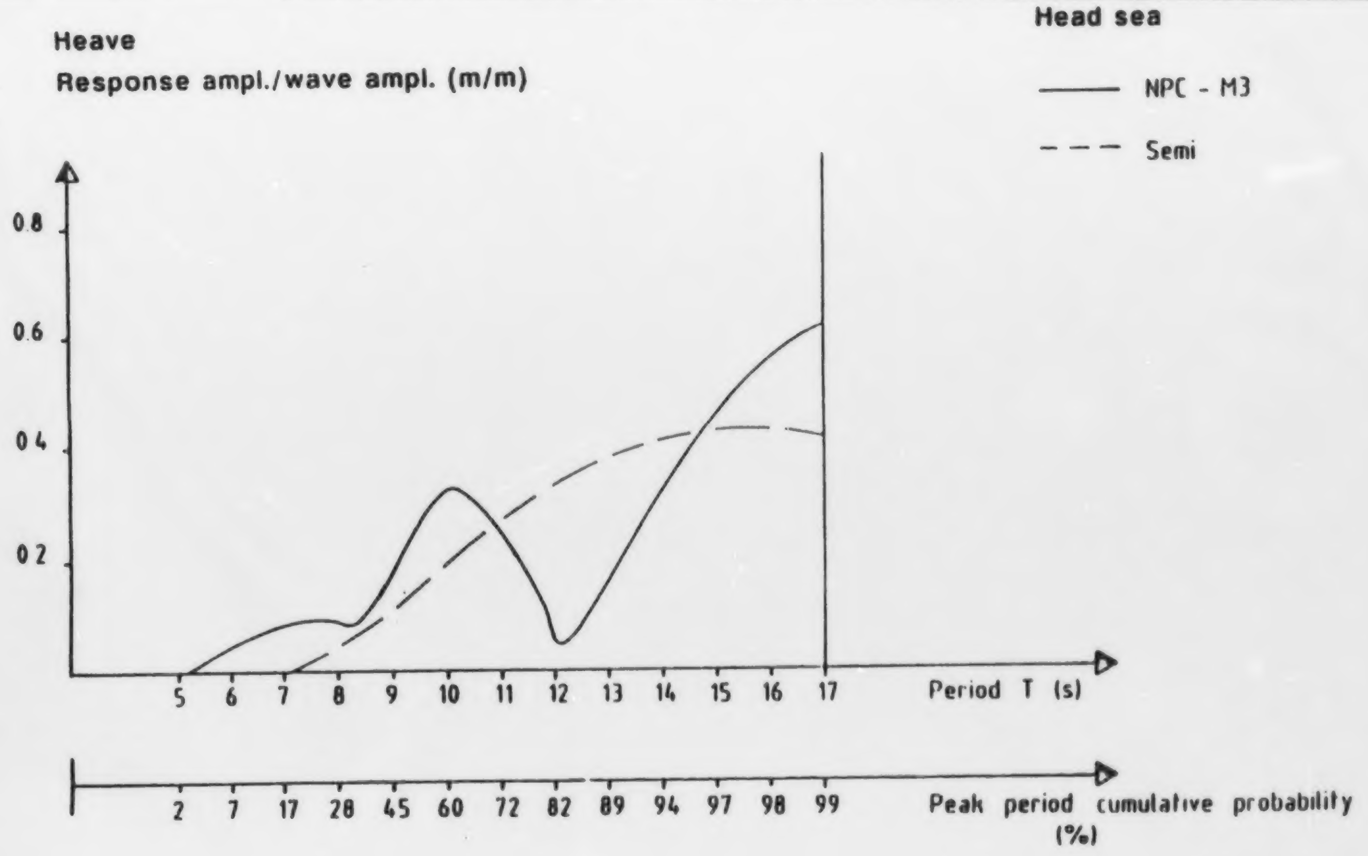
To summarize, the field development concept described here, is commercial oil prices at USD 10 per barrel, even with these conservative assumptions.



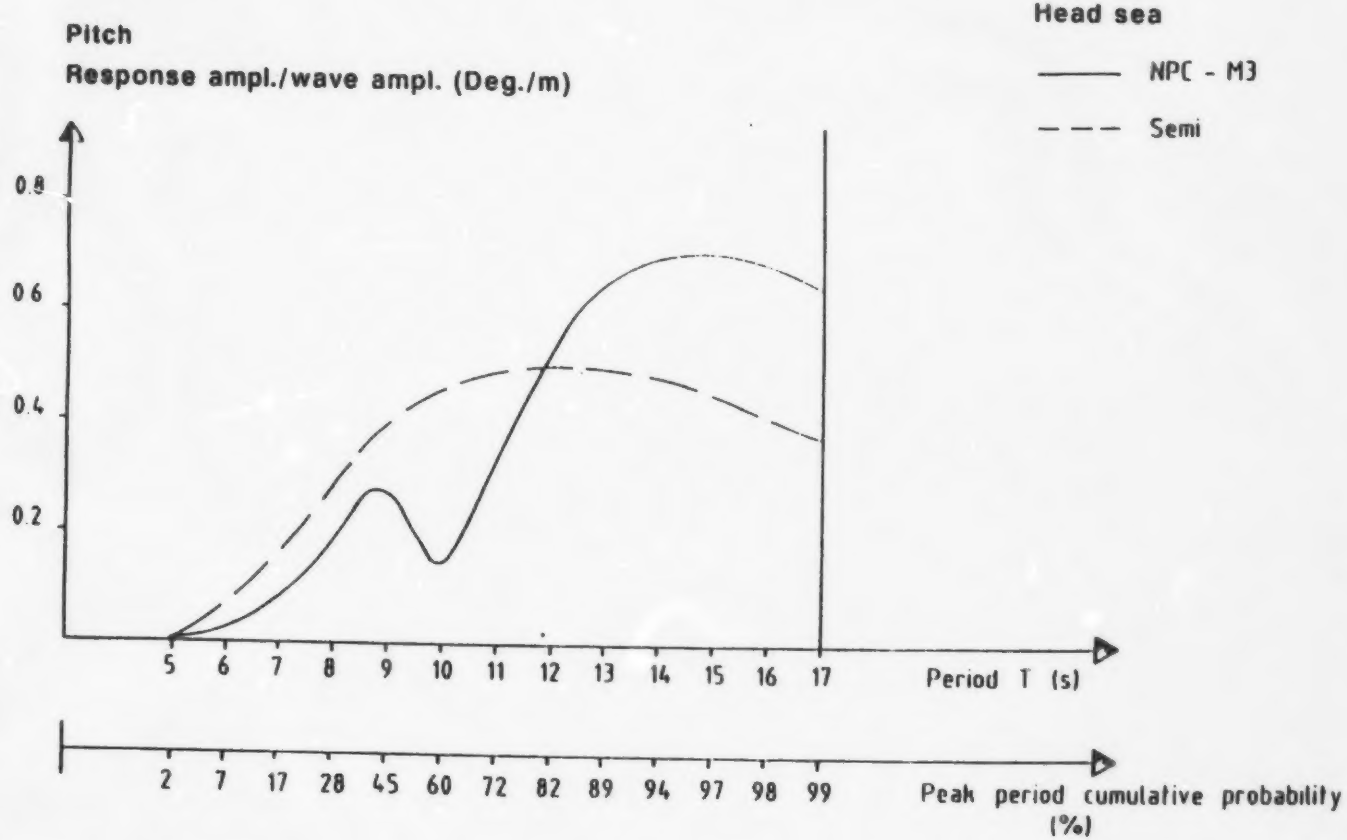
NPC-M3 - MAIN CHARACTERISTICS:

Length over all	268.50 m
Length between per.	252.00 m
Breadth moulded	46.20 m
Depth to upper deck	21.00 m
Freeboard draught	16.20 m
Design draught	15.00 m

Loaded displacement	141.000 tonnes
Crude oil storage tanks (100% filled)	93.800 m³
Methanol storage tanks (100% filled)	10.900 m³
Segregated ballast tanks (100% filled)	49.300 m³



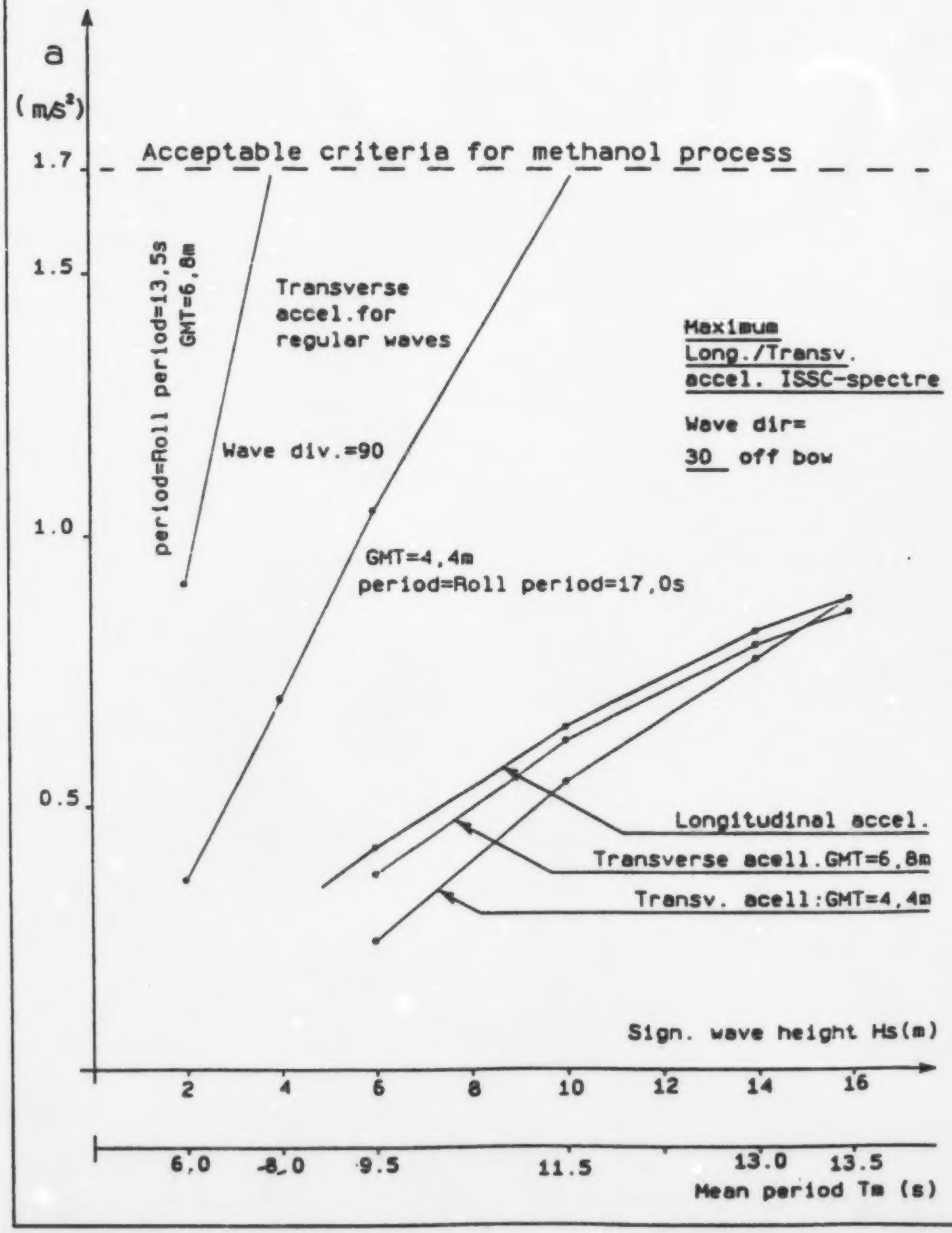
Heave response amplitude operator



Pitch response amplitude operator

ACCELERATION CHARACTERISTICS

LOADED CONDITION, ON TOP OF METH. PLANT.



SPEAKER : HANS P. ROLFSMAN

COMPANY : GVA INTERNATIONAL LTD.

LOCATION : LONDON, ENGLAND

TOPIC : INSTALLATION OF PROCESS PLANTS ON EXISTING SEMISUB UNITS RATIONALIZED

BIOGRAPHY:

Mr. Rolfsman obtained a Master of Science in Marine Engineering and Naval Architecture at Chalmers University of Technology, Gothenburg, Sweden in 1971. He has been employed by GVA since 1971 and is presently their Project Manager/ Business Development Manager.

Hans Rolfsman has eighteen years of experience in marine and offshore engineering and management, he has extensive experience in the research and development of new ships and semi-submersible vessel concepts from idea to realization. He has held the position as Project Manager for the design and construction of semi-submersible drilling rigs and for study and development work together with marketing of drilling and floating production vessels.

ABSTRACT

A cost-effective method to convert an existing semi-submersible drilling vessel to a floating production vessel is presented. The concept is applicable to any two pontoon semi-submersible of suitable size and quality for the area of interest.

The concept is characterised of a steel structure extension of the semi-sub designed large enough to carry a modularised process plant with all utilities. The extension is built up of an easy to fabricate stiffened plate steel structure possible to fabricate at any recognised shipyard building ocean going ships. On top of this structure a prefabricated process module is lifted on, hooked-up and commissioned by an offshore fabricator.

The paper describes the concept as well as a case study where a 30,000 bpd process facility installed on a third generation drilling rig of Pacesetter type. Influences on stability, motion and station keeping are also commented upon.

INTRODUCTION

This paper describes briefly the technical advantages offered by a concept for converting existing semi-submersibles into Floating Production Vessels (FPVs). Primarily units for combined production and drilling are addressed. However, the approach can be as attractive in projects where production only or tender support services are required.

While a purpose-built FPV will generally be technically and operationally superior to conversions, the lower front end investment and shorter construction time associated with conversions cannot be disregarded, especially when relatively short field lives are expected.

Conversion has usually meant rebuilding and upgrading of an existing vessel, utilising the existing facilities and squeezing in new equipment wherever possible. The number of existing vessels, inherently suited for such a conversion, is limited. Modern, third generation rigs, capable of carrying a considerable additional deck load without extensive strucutral upgradings, are comparatively few. They are also expensive, and the interest of their owners to undertake a conversion to enter a production contract is very much dependent on the prevailing market conditions. Old rigs may not always be politically viable in today's safety conscious market.

The proposed "non-integrated" approach avoids most of the problems encountered with conventional conversions. Irrespective of the project specifics, it offers substantial advantages in, for example, safety, quality, operability, cost and security of the conversion schedule:

- **SAFETY**

  The process module contains all added hazardous systems. The module is segreted from the existing systems on the orignal rig by distance, fire walls and air slots. Modern safety standards are fulfilled.

  The same segregation is not possible in conventional conversions.

- **QUALITY**

  The process module is completely manufactured in controlled conditions by an experienced module fabricator with proven track record. Standards and quality will be as customary for crude oil processing. Also the structural extension supporting the module is completely newbuilt.

- **OPERABILITY**

  The layout of the module is optimised for its purpose. Areas for escape, maintenance, mechanical handling, etc. is catered for. The process module will have minimum influence on the layout of the existing rig. This, already accepted layout will be maintained, and thus its operability retained.

  The conventional conversion is always a compromise. The existing rig with its original equipment usually puts severe restrictions on creating an optimised layout for production. Arranging areas dedicated for various purposes is always difficult.

- **SCHEDULE**

  The time schedule is basically governed by the time required for the process engineering and for the supply of long leadtime process equipment.

  The concept allows the construction of the new built structural extension, fabrication of the process plant and the final assembly into an FPV to be made independently by different specialist companies. The inter-dependence is minimised. The rig to be converted is not needed in the conversion yard for more than about 3 months.

GENERAL CONCEPT

The concept comprises a self-contained purpose-designed proces module located on an extension of an existing semi-submersible vessel. The extension is a completely independent steel structure large enough to carry the full load from the process module as well as required additional loads from mooring and other support systems. See figure 1.

The process module is designed and fabricated as an onshore commissioned lift-on module. It houses all hydrocarbon related systems, their controls and utility systems. A fire and blast wall separates the hydrocarbon systems within the module from controls and utilities which in turn faces the existing rig. The layout of the module minimises hazardous areas, pipe and cable runs as well as providing safe and efficient escape routes and access to equipment.

The concept philosophy is to avoid integration of the process utility systems with the facilities on the existing rig. This is to some degree influenced by the qualities of the existing rig, but the basic rule is to keep the existing rig "as is" as far as possible, both structurally and for the various systems. Still, some interconnection is necessary, e.g. for control purposes. Thus, the ballast control system in the new structure is inter-connected with the existing ballast control system. The new power generation plant should be sized for full oil production and normal hotel and marine demands, but without any redundancy, as power back up is provided by the existing diesel generators. Other systems interconnected are, for instance, communication and safety systems.

The process module can be fabricated by any experienced offshore module fabricator capable of handling this size of module. A typical module of 30,000 bpd production has the main dimension of 46 x 22 x 17m (excluding exhaust pipes) with a weight of about 2,000 tonnes.

The steel structure, extending the rig consists of pontoons, columns and a deck structure. The pontoons are interconnected with a cross member. The deck is mainly of a grillage type. The whole new-built unit is designed with simple fabrication in mind. This means flat surfaces, square corners and with a minimum of outfitting.

The unit is fabricated in a shipyard and mated to an existing rig which has all certificates and approvals and should remain intact as far as possible. Great care is taken in the design to make the mating simple, requiring minimum preparations of the existing rig, and hence minimum time in the conversion yard. The mating operation can take place either in a drydock or in floating condition.

Once permanently joined, the newbuilt structure and the existing rig form a new structural entity. The prefabricated process module is placed on top of the new grillage type deck.

From a naval architectural point of view, the weight of the added equipment, materials, liquids, etc. must be compensated for by increased buoyancy and stability. The new-built structure is designed to do just this, it adds to the combined entity what is needed to provide sufficient and safe deck carrying capacity and stability. Also from a structural point of view, the new cross member between the pontoons adds significantly to the structural integrity of the existing unit, providing an adequate service life. Thus strucutral modifications to the existing rig are greatly reduced. The additional mooring forces are taken by adding new mooring lines to the new-built structure.

With regard to certification, the process plant and the new-built structure are built to meet the applicable codes and standards. The existing rig is already certified for operation as a drilling vessel. This vessel is not changed significantly. The general layout and safety is as previously certified.

The combined unit will be approved on its qualities as a single entity for production and drilling. Its intact and damage stability, its structural fatigue life and its ability to operate safely must be demonstrated to the satisfaction of the Certifying Authority. When going into a more detailed review, it is expected that the Certifying Authority will take due consideration of the existing approvals to the degree compatible with the new service.

After terminated service, it is comparatively simple to re-convert the vessel back to a drilling rig, if so desired.

The concept has been developed by GVA and is named PROMS (Process Module Systems). It has been presented to the UK Department of Energy and the Norwegian Petroleum Directorate. Patent is applied for.

A 30,000 pbd Case

The following has been studies in detail. A process plant design to meet the following main data was chosen:

Gross fluids	35,000 pbd
Oil, peak production	30,000 pbd
Produced water	14,000 bpd
Gas/oil ratio	700 cuft/bbl
Water injection, peak	40,000 bpd

Further, the following assumptions were made:

- Flexible risers were used.
- Oil was exported via a pipeline.
- Gas, in excess of what was to be consumed as fuel, was flared.
- 10 production wells were arranged in a loose cluster, with an additional production well and 3 water injection wells arranged as satellites.
- The FPV would be located over the cluster, allowing those wells not pre-drilled to be drilled simultaneously with production.

A Pacesetter-type drilling rig was selected for the study. The rig was built by GVA and delivered in 1982. It complies with the requirements of the Norwegian Maritime Directorate, and has a Certificate of Fitness to operate on UKCS and Offshore Eastern Canada.

Figure 2 - 4 shows the converted rig with the PROMS extension including process module fitted.

The process plant is prefabricated and mounted in a truss type support structure which is placed on the deck (figure 5). Its layout is determined by the process demands, the only restriction is the general size of the module. The control rooms and switchgear rooms are fire and blast protected on their exposed surfaces, and this protection is extended as a wall athwardships on the upper module (separator) deck.

The riser connection is at the aft end of the vessel, well away from the moonpool and accommodation. All hazardous systems are in open naturaly ventilated areas. Dedicated areas for riser interface and production systems are well segregated from the rest of the rig, the layout of which is not changed. No mechanical handling operations do usually have to be carried out over the process/riser areas. The full drilling capability is retained.

The steel structure extending the rig and supporting the process module and riser balcony is shown in figure 6.

Gas flaring is provided through extending the existing drilling derrick and locating a high velocity flare tip on top of the extension. Similar flares are used with excellent experience in the North Sea.

Weights and stability

After conversion and extending the original vessel with the PROMS concept, a deck carrying capacity (figure 7) of 4,750 tonnes is reached fulfilling UK Department of Energy requirements as expressed in a draft dated January 1986.

This deck carrying capacity corresponds almost exactly to the variable deck load for the existing vessel plus the process plant including process liquids. In other words, the extension has provided stability to the original rig large enough to carry both the process module in an operating condition and the additional mooring loads without any sacrifice of drilling capability.

Weights and deck payloads are given in table 1.

With further increased waterplane area of the columns of the extension and with fenders mounted on the mid columns of the existing vessel, the available deck carrying capacity will increase to above 7,000 tonnes.

If also the drilling equipment of the existing vessel were removed, another 1,500 tonnes could be gained, increasing the total available deck carrying capacity of the unit to above 8,500 tonnes.

Motions

The addition of the new structure to the existing vessel changes its original dynamic behaviour.

A comparative calculation was performed to analyse this difference in behaviour and its influence on the vessel's operating characteristics. Calculations of response in regular seas were performed using a 3-D difraction theory which was then linearly superpositioned with am ISSC spectrum. Checks were also made considering non-linear viscous damping.

The results of the analysis are that the motions for the converted vessel are very similar to that of the original vessel or even somewhat improved. The operability as a drilling rig will remain very good and as a production vessel the motions are not expected to cause any downtime.

A comparison of the motions between the original rig and the converted one is presented in Table 2 & 3. The responses in irregular short crested sea can further be summarized as follows:

Heave	Somewhat improved motions in particular in low sea states
Roll	Improved motions over the whole range of sea states
Pitch	Slight increase of motion in heavy seas. The change is comparitively small and has no impact on operability
Sway and Surge	Similar or slightly improved motions

The operability of the vessel as a drilling rig can be expressed in terms of excedence of threshold values in motion for certain operations. For drilling and work-over operations the following limits of vessel motions in double amplitudes have been investigated:

Drilling	Significant heave	3 metres
	Significant roll/pitch	4 degrees
BOP handling	Significant heave	1 metre

The excedence frequency was calcualted using a long term Weibull distribution of maximum wave heights. The results are presented in Table 4 and shows that no difference in drilling operability is expected.

Station Keeping System

The staion keeping system was checked to suit a typical North Sea location on the UKCS. The environmental data on the location was:

Wind speed, 1 min mean	42.9 m/s
Significant wave height	13.6 m
Zero upcrossing period	12.5 sec
Surface current speed	1.65 m/s
Water depth	110m

The mooring system should fulfil Department of Energy requirements. Intact system, one line failure and transient condition at line failure were looked at.

To fulfil these requirements two additional mooring lines of similar type as the existing (3" K4 chain) gave a good margin in all cases. The lines were attached to the extension, one at each additional column spreading 20 degrees from the centreline.

The existing two azimuth thrusters have not been considered in the mooring analysis.

Built-in Crude Oil Storage

The above concept has been designed for pipeline export of the produced crude. If this is not feasible an intemediate crude oil storage system within the FPV or in its offloading facility will greatly enhance the availability of the entire production facility.

The semi-submersible extension with its "fat" cross pontoon is particularly suited to house such a storage system. GVA has developed an oil-on-water storage tank system suitable for semi-submersibles which can be incorporated in a somewhat enlarged cross pontoon. A storage volume of 70,000 bbl has been achieved without any adverse effects on the semi-submersible operation criterias. A typical arrangement is shown in figure 8.

Table 1

Increased Light Unit Weight:	
Additional Steel	2150
Additional Basic Outfit	200
Main Facilities (Process Module)	1650
Total	4000
New Deck Payload:	
Drilling Variables	1500
Process Liquids	400
Flexible Riser Tension	200
Crew, Provision	100
Miscellaneous	100
Remaining Available	800
Total	3100
Increased Mooring Load	
Total	300

Table 2

Short term response of original design in irregular short crested seas, operational draft

Zero-upcrossing Period, T_z (s)	SURGE	SWAY	HEAVE		ROLL	PITCH
	head sea (m/m)	beam sea (m/m)	head sea (m/m)	beam sea (m/m)	beam sea (deg/m)	head sea (deg/m)
6	.15	.15	.16	.14	.36	.34
8	.33	.32	.29	.27	.47	.44
10	.47	.46	.43	.42	.47	.44
12	.56	.55	.75	.75	.43	.41
14	.62	.61	1.01	1.01	.38	.37

Table 3

Short term response of converted vessel in irregular short crested seas. Operational draft.

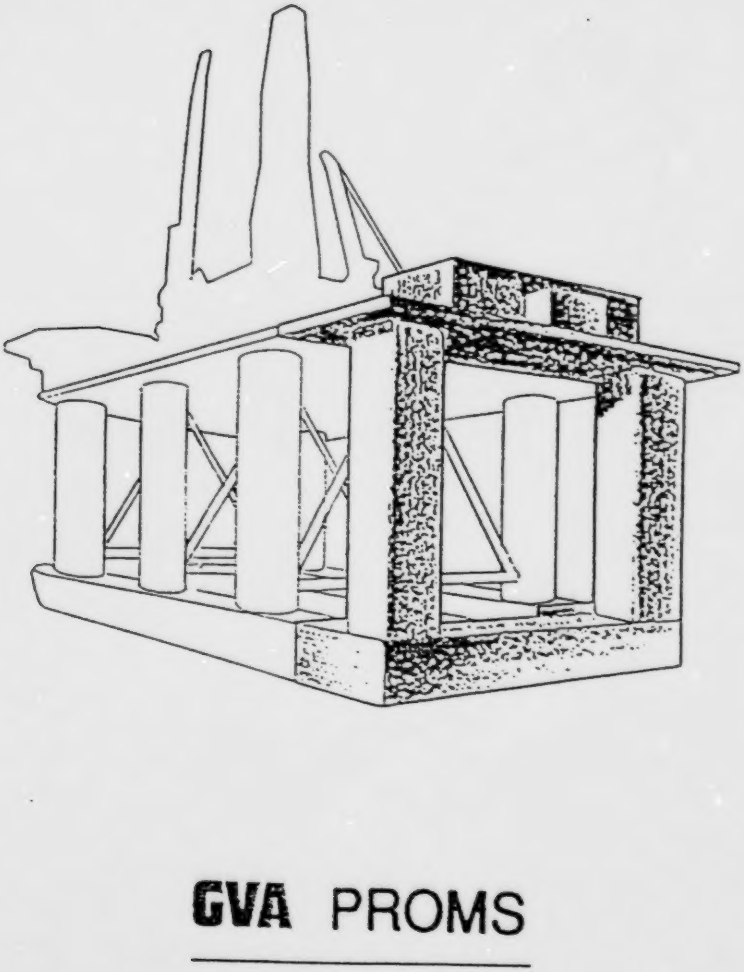
Zero-upcrossing Period, T_z (s)	SURGE	SWAY	HEAVE		ROLL	PITCH
	head sea (m/m)	beam sea (m/m)	head sea (m/m)	beam sea (m/m)	beam sea (deg/m)	head sea (deg/m)
6	.12	.14	.13	.13	.30	.30
8	.29	.31	.29	.29	.40	.43
10	.43	.45	.45	.44	.41	.48
12	.54	.55	.76	.76	.37	.60
14	.61	.61	1.00	1.00	.33	.68

Table 4

Excedence frequence of sea state for drilling operation

Operation	Motion	Limiting	Original vessel			Converted vessel		
		sign value	Max Sea State		Sea State Excedence	Max Sea State		Sea State Excedence
		(m or deg)	H_s (m)	T_z (s)	part of year	H_s (m)	T_z (s)	part of year
Drilling	Heave	3.0	8.6	9.2	2.00×10^{-5}	8.5	9.1	2.39×10^{-5}
	Roll	4.0	8.3	9.0	3.00×10^{-5}	9.8	9.7	0.48×10^{-5}
	Pitch	4.0	9.0	9.3	1.3×10^{-5}	8.5	9.1	2.39×10^{-5}
BOP	Heave	1.0	4.6	6.7	3.08×10^{-3}	4.8	6.9	2.31×10^{-3}

Figure 1



GVA PROMS

Figure 2

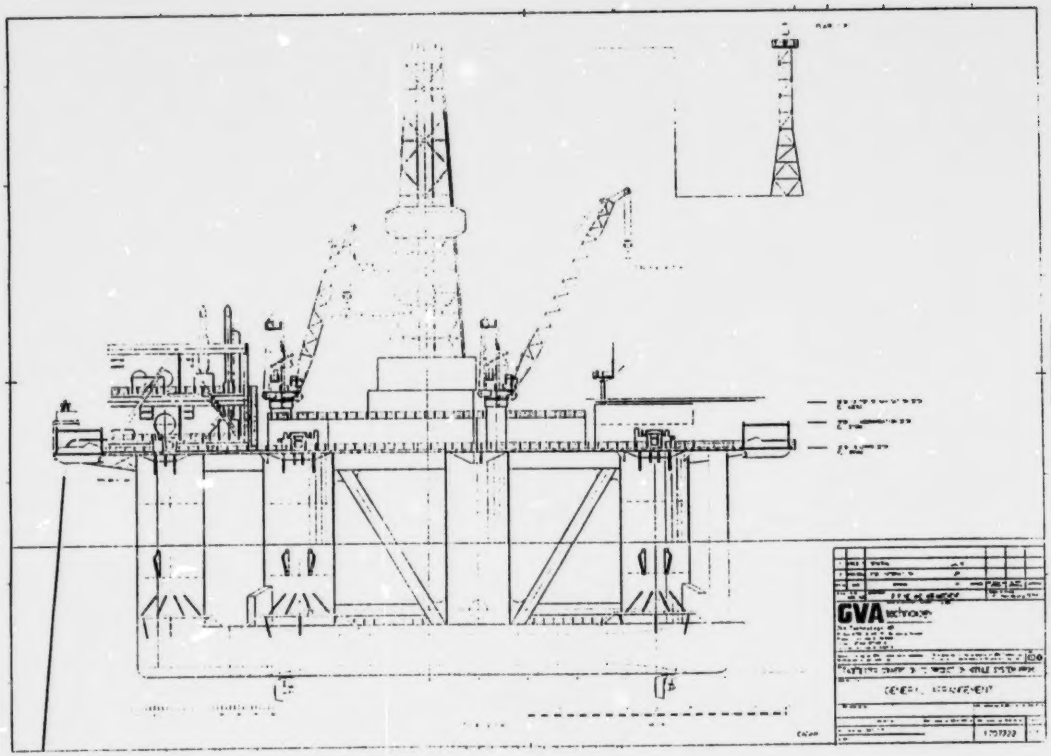

GVA
GENERAL ARRANGEMENT

Figure 3

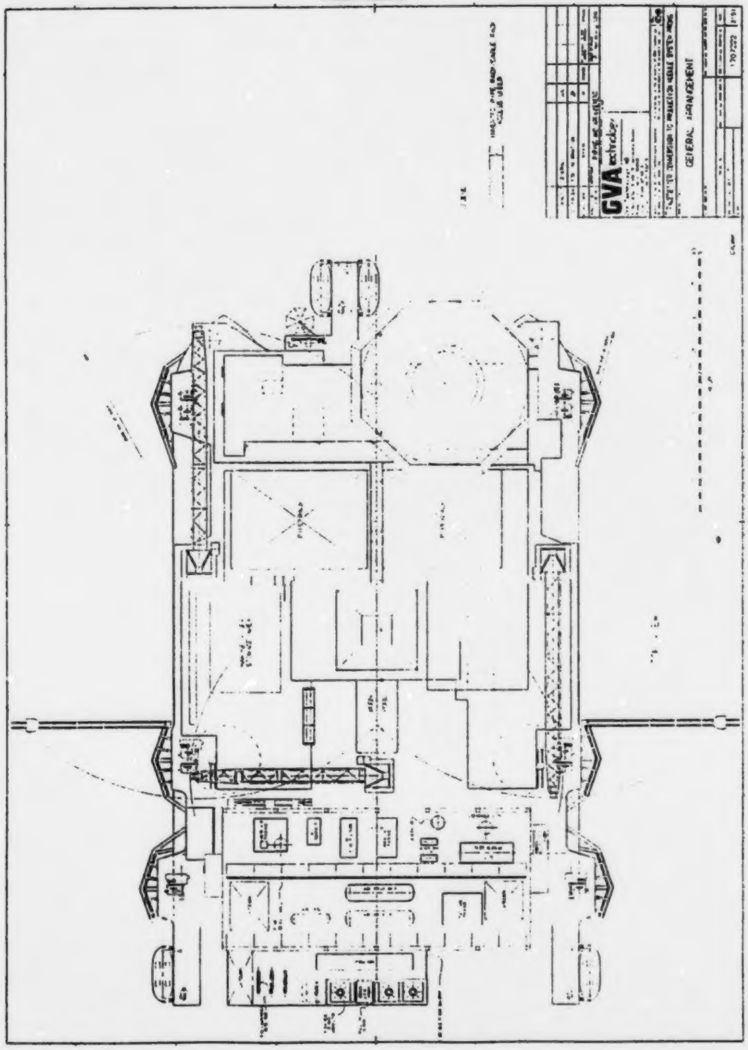

GVA
GENERAL ARRANGEMENT

Figure 4

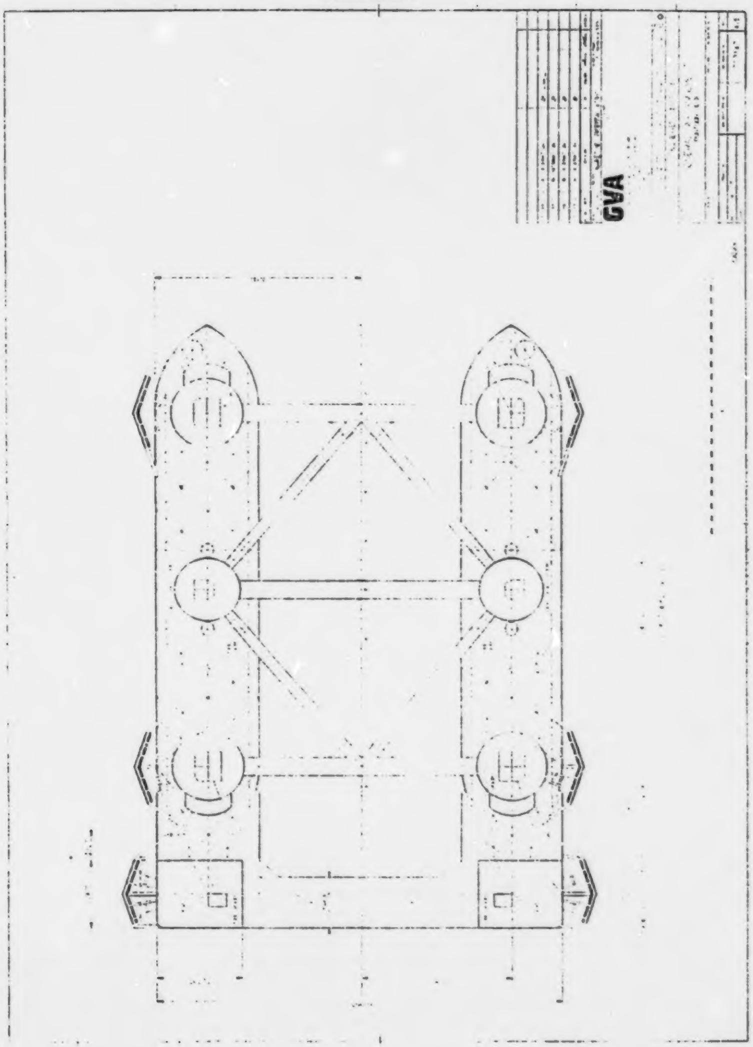


Figure 5

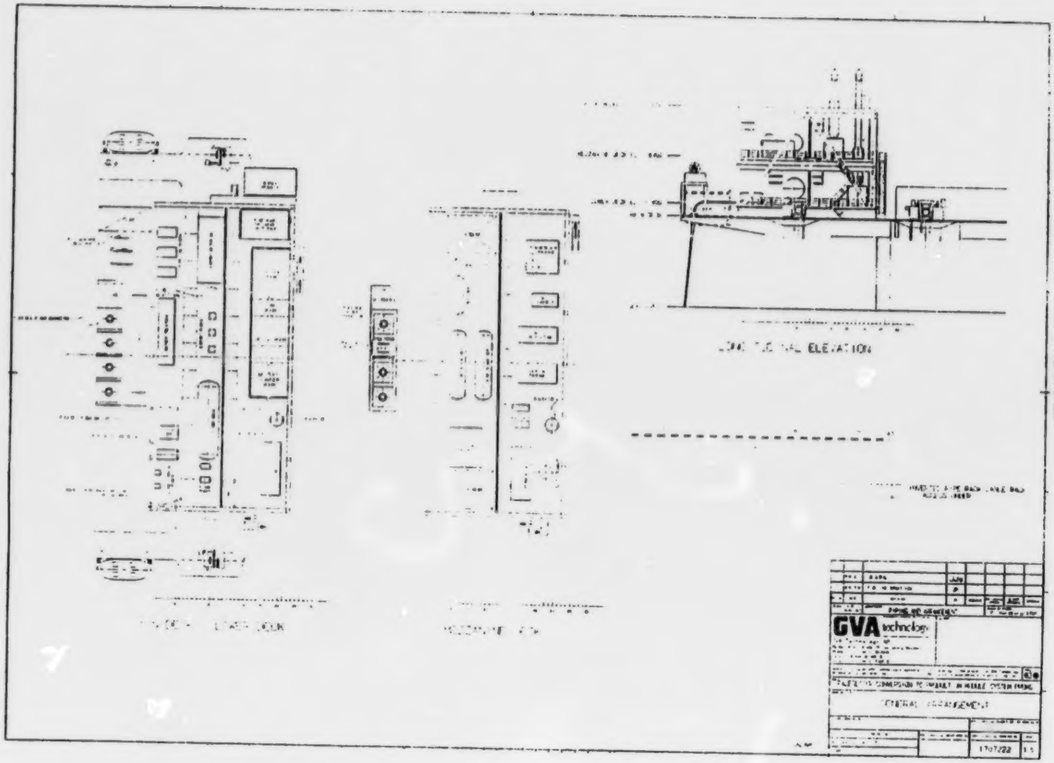

LONGITUDINAL ELEVATION
GVA technology
GENERAL ARRANGEMENT
1707/22

Figure 6

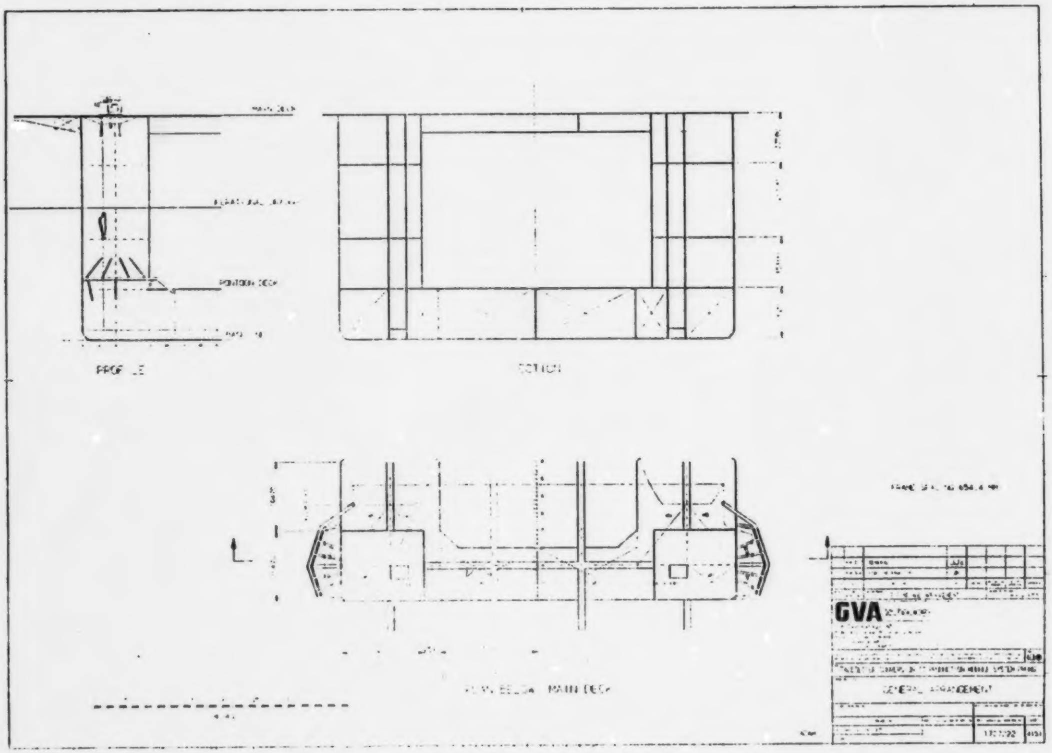

MAIN DECK
PONTOON DECK
PROFILE
SECTION
PLAN BELOW MAIN DECK
GVA
GENERAL ARRANGEMENT

Figure 7

Definition of deck carrying capacity

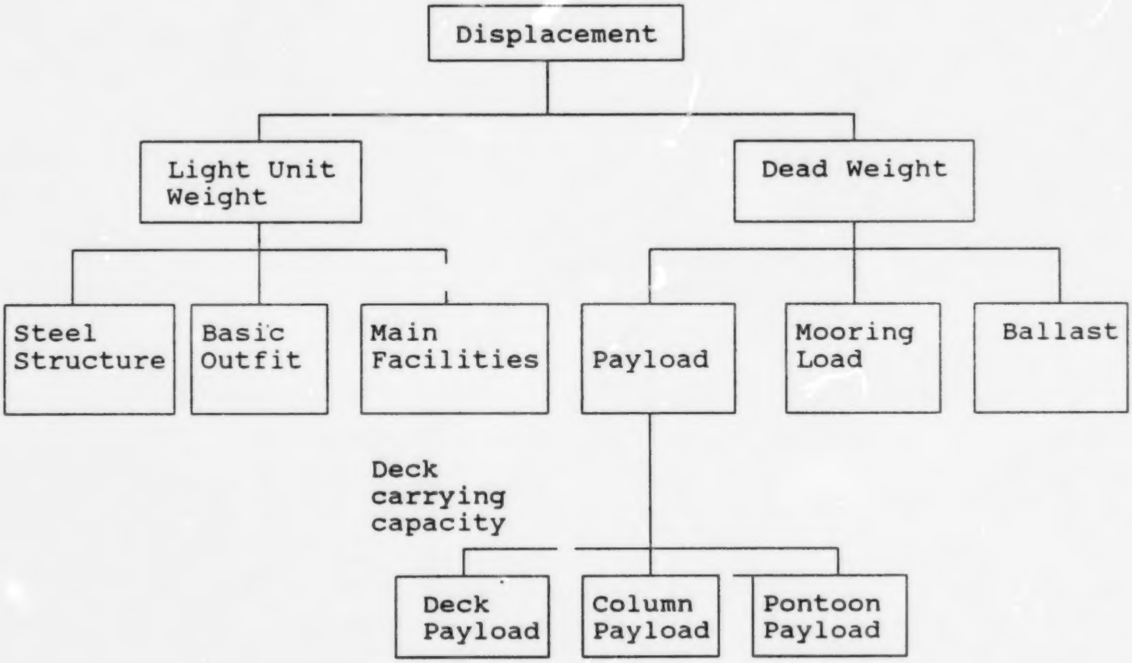
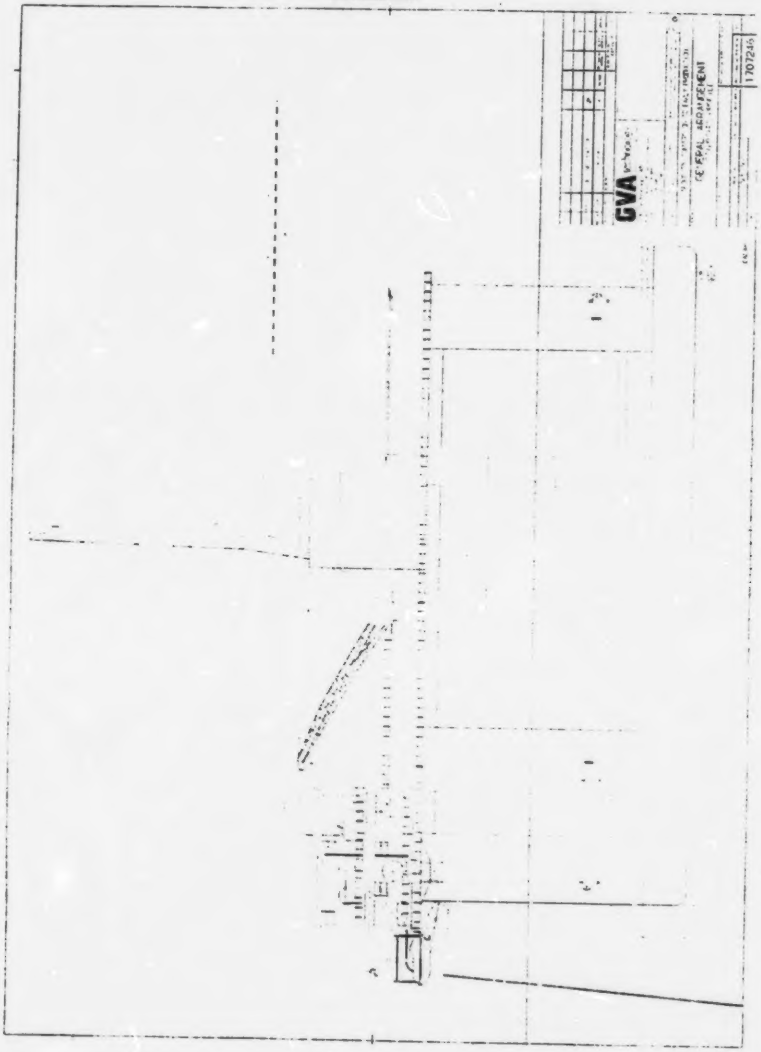

Displacement
Light Unit Weight
Dead Weight
Steel Structure
Basic Outfit
Main Facilities
Payload
Mooring Load
Ballast
Deck carrying capacity
Deck Payload
Column Payload
Pontoon Payload

Figure 8


GVA
GENERAL ARRANGEMENT
1707246

SPEAKER : **GERRY C. GERMAIN**

COMPANY : **BOUYGUES OFFSHORE CANADA LIMITED**

LOCATION : **MONTREAL, CANADA**

TOPIC : **CONCRETE SEMI-SUBMERSIBLE FOR THE GRAND BANKS**

BIOGRAPHY: Mr. Germain is President of Bouygues Offshore Canada Limited. Between 1984 and 1988 he was a Director of Bouygues Offshore's British operations for the North Sea and is past Deputy Chairman of the U.K. Module Constructors Association.

Prior to joining Bouyges, Mr. Germain worked with a London-based engineering group and was involved in the design and construction of major North Sea oil and gas developments. Born in Montreal, he was educated at College St. Laurent and Sir George Williams University.

ABSTRACT

This paper describes aspects of an ongoing development program that is being carried out for the NEKTON 8000 FPV, a concrete hull semi-submersible vessel designed for application in areas having harsh environmental conditions such as the Grand Banks of Newfoundland.

The development studies cover a broad range of subjects including the design of the hull, deck structure and vessel systems, hydrodynamic and ice impact model testing, as well as global and local finite element structural analysis. The constructability in Newfoundland, availability of local concreting materials, scheduling and construction costs were also investigated.

INTRODUCTION

The NEKTON 8000 FPV's concrete hull is composed of a rectangular ring pontoon and six columns. The concrete hull supports the steel deck structure which houses the process facilities, services and accommodations. (See Figure 1).

The vessel can support, within the deck structure, up to 3000 tonnes of process facilities and associated secondary steel at the transit draft and up to 5000 tonnes at the operating draft, in addition to power generation, services and accommodations. The deck structure and layout can be modified, if required, to support drilling and workover facilities, in addition to production operations. The hull ballast tanks and systems can, if necessary, be designed for crude oil storage.

The vessel would be moored by a twelve line catenary mooring system and is designed to remain on station in all conditions, except those which include the threat of collision with an unmanageable iceberg. Connection to a subsea manifold is provided by a series of flexible risers.

In the event that the vessel is required to move off station, the mooring lines and the risers can be quickly and efficiently disconnected and the vessel self-propelled away using its four thrusters.

The main characteristics of the NEKTON 8000 FPV are outlined in Figure 2.

DESIGN PARAMETERS

The basic design of the NEKTON 8000 FPV complies with all applicable standards, rules and regulations. A Concept Approval Certificate was issued by Bureau Veritas on May 25th, 1989. (See Figure 3).

HULL STRUCTURE

The hull structure of the vessel is designed to be constructed from high-strength post-tensioned concrete. The hull consists of a rectangular ring pontoon topped by six vertical columns. (See Figure 4).

The ring pontoon is rectangular in plan with overall dimensions of 94.0 m x 80.0 m. The pontoon is rectangular in cross-section having a width of 18.0 m and a height of 13.0 m. The columns have an external diameter of 18.0 m and extend 39.5 m above the base. A 9.0 m diameter inner column wall extends 32.0 m above the base. Horizontal slabs at levels 13.0 m and 32.0 m divide each column into watertight compartments.

The concrete ring pontoon is subdivided by a series of watertight concrete bulkheads separating the hull into compartments which are used for diesel fuel and fresh water storage and sea water ballast.

The watertight compartments within the columns and ring pontoon comply with the stability parameters in intact and damaged conditions.

USE OF HIGH STRENGTH CONCRETE

High-strength (70 MPa), prestressed concrete was selected over steel as the hull construction material for the following reasons:

- Concrete has good inherent resistance to impact loads and can be easily and economically designed and built to withstand high local ice forces
- Concrete has excellent durability in the marine environment and a concrete hull requires no maintenance
- Correctly designed prestressed concrete structures are immune to fatigue, thus a concrete hull has excellent resistance to cyclic loads, and therefore has a long design life
- Concrete is an ideal material for use in northern environments since its strength is virtually unaffected by freeze/thaw cycles, ice formation and temperature differentials between outside and inside
- The construction can be performed in Newfoundland by manpower with civil works experience and using standard techniques and equipment
- The cost of a concrete hull is significantly less than a comparable steel hull.

PRODUCTION OF HIGH STRENGTH CONCRETE

A test program was carried out by Memorial University of Newfoundland and Newfoundland Geosciences Limited to identify suitable local sources of aggregates and to perform production tests with locally available cements and required admixtures to produce 70 MPa concrete.

Results from the test program have determined that 70 MPa concrete can be produced using local materials and with the implementation of quality assurance and quality control programs, consistent results would be achieved.

HULL DESIGN

The hull design was performed using various computer programs, commencing with Aquadyn for the hydrodynamic analysis, followed by Abaqus for the structural analysis and various in house computer programs for the verification of the concrete sections and the sizing of reinforcement and prestressing steel.

The limit states which have been considered for the design are:

- SLS: serviceability limit state governing durability
- ULS: ultimate limit state governing general safety factors on loads and materials
- PLS: progressive collapse limit state governing survival after an isolated accident

Characteristic design values for the structure are:

- concrete compression characteristic strength, fck = 70 MPa
- reinforcement steel elastic limit yield strength, fsy = 400 MPa

Note: for congested areas and areas subject to impacts, higher steel grades might be used with yield strength of 500 or 600 MPa.

- prestressing steel: 12 and 19K15 cables composed of 12 and 19 strands respectively of 15.47 mm diameter, grade 1760 steel would be used. Low relaxation strands would be used.

The hull structural analyses were performed for several platform situations and, within each situation, for several load cases.

In the operating and transit situations, the considered load cases included deadweight, equipment loads, buoyancy, mooring loads, several alternatives for filling the water ballast compartments, variations of variable loads, wind loads, current loads, effects of a heel angle and several wave loadings. Each load case was always fully balanced by adequate buoyancy forces, mooring forces, water ballast or inertia forces, according to the actual loading.

For both operating and transit situations there were 29 basic load bases analyzed with Abaqus and 27 combined cases derived from the previous ones with the post-processor. In all, a total of 130 load combinations have been studied for the hull structural analysis.

The design of the hull structure, which has been completed based on the results of the above analyses, has not incorporated the effect of ice loading. An investigation has been performed to determine the inherent ice resistance of the hull as it is designed. The results of the investigation have illustrated that the hull can resist an iceberg impact force having a return period of 940 years. Details of this investigation are presented in a later section of this paper. Further analysis is required before the final hull design is established.

DECK STRUCTURE

The deck structure of the vessel has been designed to provide support for process facilities, services and accommodations. The vessel is designed to operate in areas of harsh environmental conditions including atmospheric icing. Due to these conditions the process facilities and services are located within the deck structure.

The three tiered deck structure is made up of a network of longitudinal and transverse truss beams and bulkheads. The truss beams and bulkheads subdivide the deck structure into fifteen zones (pancakes) in plan view. (See Figure 5). Two transverse fire/blast bulkhead walls segregate the process area from the services area and the services area from the accommodations.

The process area is bordered on three sides by louvred open truss beams to allow for natural cross ventilation.

Alongside the two interior longitudinal truss beams, which run the full length of the vessel, are dedicated escape routes which lead to the lifeboat stations at either end of the vessel. A network of transverse escape routes are used to feed these two longitudinal escape routes, thus providing safe passage from each area on the vessel.

The final design, layout and carrying capacity of the deck structure would be on the basis of an operator's development criteria.

MOORING AND RISER SYSTEMS

A key characteristic in the viability of a floating production vessel for use in the environment which exists on the Grand Banks of Newfoundland is the ability of the vessel to move off its production station safely and efficiently when in danger of iceberg collision.

A portion of the development program was dedicated to the design of systems which ensure the vessel's mobility. Several disconnection procedures have been worked out, each a function of the sea state and the estimated lead time available before the vessel is required to move off station. In order to optimize production efficiency and reduce down time, quick reconnection procedures have also been developed for the mooring and riser systems.

The vessel would be moored by a twelve line catenary mooring system. Each mooring line consists of a lower chain linked to a large diameter anchor pile, clump weight and upper chain leading to a windlass.

Three mooring disconnection procedures have been anticipated:

i) Normal Condition - sea states up to Beaufort 8. Estimated duration: 3 hours. Operation reversible

ii) Storm Condition - sea states beyond Beaufort 8. Estimated duration: 3 hours. Operation reversible up to a line(s) tension of 200 tonnes.

iii) Emergency Condition - in all sea states. Estimated duration: within 10 minutes. Operation not reversible.

The flexible risers are designed to accommodate all anticipated motions of the vessel. Computer analyses have been performed to study the dynamics of the vessel and to check the behaviour of the risers to avoid chafing of adjacent lines.

The risers are connected to the vessel through a common riser beam. The risers can be disconnected from the vessel simultaneously by disconnection of this riser beam which then acts to keep the risers together and suspended approximately 45 m below the water surface. Ball valves located at the top of the risers and at the subsea manifold, would be closed prior to disconnection.

Two riser disconnection procedures have been anticipated:

i) Normal Condition - in all sea states.
Estimated duration: 3 hours. Operation reversible.

ii) Emergency Condition - in all sea states.
Estimated duration: within 10 minutes. Operation not reversible.

During all of the above disconnection operations, the vessel would be manoeuvred and moved off station using its four thrusters. The navigational control of the vessel can be performed either by a computer controlled dynamic positioning system or by a manually controlled navigation system.

During the reconnection procedure, the riser beam would be located and reattached to the vessel, thus bringing all the risers to the vessel simultaneously. The risers would then be reconnected to the vessel, the connections pressure tested and oil production resumed.

The reconnection procedure can be carried out in sea states lower than Beaufort 6 and the estimated duration, including pressure testing of each riser connection, is less than 20 hours. For the reconnection operation two anchor handling vessels are required, in addition to a small diving team to assist in the reconnection of the riser beam to the vessel.

HYDRODYNAMIC ANALYSIS AND MODEL TESTING

An extensive hydrodynamic analysis was performed in order to optimize the hull geometry and to minimize the wave motion response of the NEKTON 8000 FPV.

L'Institut Francais du Petrole used the computer program, AQUADYN, to calculate added mass, damping matrices, natural periods, response amplitude operators (RAO) and wave drift forces. The slow drift motions of the vessel were simulated using another program, SIMSEM. The developed computer model was used as the basis for a physical test program. The results of the test program were then used to confirm and/or revise the computer model.

The Institute for Marine Dynamics of The National Research Council of Canada was commissioned to perform a comprehensive model testing program using a 1:45 scale model of the NEKTON 8000 FPV. The main purpose of the testing program, which investigated the response of the model under the combined effect of waves, wind and current, was to confirm that the total motion of the vessel and the loads in its anchor lines would remain within acceptable design limits. The tests were carried out for 95 m and 315 m water depths at both the operational and transit drafts of the vessel. The model was tested in a variety of sea states in head, beam and quartering seas.

The hydrodynamic model testing program investigated the response of the vessel in the 1 and 100 year storm criteria for the Grand Banks of Newfoundland. Investigation into the vessel performance with one of its mooring lines damaged and with the assistance of the thrusters was also performed. (See Figure 6).

The global loads on the vessel due to the superposition of waves, wind and current as calculated by the computer model correlated very well with the loads measured during the physical testing program. (See Figure 7 for a comparison of sample results).

During the tests the amount of evident deck wetting or splashing was minimal and occurred only in the most severe sea states. This phenomena had not been detected with the computer model for two reasons:

i) The physical model tests illustrated that the heave and roll natural periods of the vessel were slightly lower than predicted by the computer model,

ii) The run-up of water on the columns had been calculated by the computer model based on a linear wave diffraction theory; in the physical model, it was evident that for higher wave crests a non-linear phenomena occurred.

Limitations had been placed on the physical modelling of the anchor lines due to the size of the model basin. The computer model of the vessel however, reproduced the lines realistically both vertically and horizontally. The measured natural periods for the moored conditions appeared slightly lower than the natural periods for the free floating conditions due to an extra added stiffness introduced by the mooring system. As a next step in the modelling process, a numerical simulation of the anchoring system characteristics as observed in the model basin will be performed.

On the basis of a preliminary analysis it has been determined that the overall behaviour of the NEKTON 8000 FPV under the effects of waves, wind and current is very satisfactory. Analysis of the model testing program is continuing.

ICE/STRUCTURE INTERACTION

An ice/structure interaction study was carried out by the Centre for Cold Ocean Resources Engineering (C-CORE) to identify procedures to calculate sea ice and bergy bit impact loads on the NEKTON 8000 FPV and to estimate the probability of occurrence of these loads.

The study program was divided into four phases:

Phase I : Ice Environmental Data
Phase II : Wave Driven Bergy Bit Impact Tests
Phase III : Sea Ice Tests
Phase IV : Risk and Reliability Analysis

In conjunction with the above study program, local structural analysis has been performed to investigate the inherent ice resistance of the concrete column wall under the effect of ice loading. The results of the C-CORE study have been incorporated into this structural analysis.

Phase I, Ice Environmental Data

Phase I consisted of the identification and compilation of environmental conditions occurring on the Grand Banks of Newfoundland. Five topics were investigated; sea ice, icebergs, ice accretion, environmental (wind, waves, temperature, etc.), and ice management.

Figure 8 presents a summary of several ice environmental parameters and values as specified by C-CORE.

Phase II, Wave Driven Bergy Bit Impact Tests

Phase II consisted of a series of impact tests conducted in the wave tank at the Memorial University of Newfoundland to investigate wave induced bergy bit impacts of 1000 and 5000 tonnes with a 1:75 scale model of the vessel. The objective of the experimental program was to develop a procedure and a methodology to collect and analyze a statistical set of iceberg impact velocities and locations for the purpose of providing design information for ice strengthening the structure.

The test program involved the tracking of the experimentally modelled iceberg position and the vessel model position. The independent positions of both the iceberg and the vessel were computer simulated and the relative positions of each were analyzed to determine the number of impacts and the position on the vessel at which each impact occurred. Both the open water iceberg velocities and the near vessel iceberg velocities were measured.

The results illustrated that wave diffraction from the vessel affected the berg impact velocities and could change the berg approach directions. The influence of the vessel on the approaching iceberg was more significant for the smaller berg than the larger one. For example, in head seas orientation, wave diffraction caused fewer impacts of the small berg with the vessel and no impact in the beam sea orientation. The tests illustrated that for the two size bergs investigated, the most likely impact location was the top exterior corner of the pontoon regardless of the rig orientation and berg release location.

The impact of these results on the design of the concrete pontoon is the subject of further structural analysis.

Phase III, Sea Ice Tests

Phase III consisted of a series of model tests which were performed at the Institute for Marine Dynamics ice laboratory in St. John's to assess the behaviour of the vessel in sea ice and to measure the applicable ice forces. A 1:45 scale model of the vessel was tested in both a "fixed" and a moored configuration for three orientations of the model, two ice thicknesses, and three velocities. In the "fixed" configuration, ice forces were measured by a six-axes force and moment sensor which was positioned at the point of attachment of the towing frame to the towing carriage. In the moored configuration mooring line tensions, linear accelerations, as well as pitch, roll and surge displacement were measured. One column of the model was capable of free translation in the horizontal direction and was instrumented with two x-y load sensors. Four columns were instrumented with pressure sensitive film to measure ice pressure.

The most important feature shown by the sea ice tests is the importance of dynamics. It was hoped to isolate this feature by comparing test results of the fixed versus moored configurations. An example of the results obtained in the ice tests is presented in Figure 9. This figure presents a summary of forces measured for the fixed and moored model configurations at the 45° orientation in approximately 11mm model ice thickness. The tests indicated that the loads did not necessarily increase as the speeds increased. The moored tests also illustrated that at the lowest tested velocity, a ratcheting action occurred, resulting in a sawtooth profile of force and displacement versus time.

The results of the sea ice test have been used to verify and confirm the local structural resistance of the concrete hull to sea ice interaction. The results will be used in further design phases of the vessel's mooring system.

Phase IV, Risk and Reliability Analysis

Phase IV was carried out to determine:

1) the probability distributions and design values for collision kinetic energies and loads on the columns and pontoons of the vessel due to icebergs,

2) an estimate of the downtime to oil production resulting from operations suspension and vessel relocation due to iceberg encroachment, and

3) an estimate of the downtime to oil production due to sea ice encroachment.

1) Iceberg Collision

Based on work that has been carried out by Jordaan, 1988 for the Canadian Standards Association (CSA, 1989) Program for Fixed Offshore Structures, the study proposed that the appropriate annual exceedance level for the accidental design load should be taken as 10^{-4} per year, i.e., a return period of 10,000 years. This value has been chosen despite the fact that it is for fixed structure application since no equivalent work has yet been conducted for floating structures. To estimate the 10^{-4} per year design force, the following steps were taken:

i) From the environmental data gathered in Phase I, the rate at which icebergs would be encountered at the operation location and the distribution of sizes that would result if no iceberg management was in place was determined.

ii) A computer model was developed which simulated the effect of iceberg management. The methods of iceberg management investigated were both iceberg towing and vessel emergency relocation.

iii) A computer model was developed which calculated the maximum collision forces on the column of the vessel due to impact. These collision forces were based on the environmental data previously compiled and assumed an idealized iceberg shape.

iv) The probability distribution of iceberg collision kinetic energy and force (given a collision) was calculated using Monte-Carlo simulation.

v) The design force (10^{-4} probability per year of exceedance) was determined using extremal analysis from the exceedance distribution of forces and collision encounters.

The design load determined by the above methodology which corresponds to an iceberg impact having a return period of 10,000 years is 190 MN.

2) Iceberg Encroachment

To estimate the downtime to oil production resulting from iceberg encroachment near the operating site of the NEKTON 8000 FPV, an alert zone operations system was developed. The amount of downtime due to iceberg encroachment will be dependent on the size of the zones, the number of icebergs and the amount of time each iceberg remains in the alert zones, as well as the time required to restart operations after each iceberg incursion. Several example calculations were carried out for the study, however, the actual downtime incurred will depend on the operating procedure adopted.

3) Sea Ice Encroachment

To determine the downtime due to sea ice, areal concentrations of sea ice were determined for the location 46.5° North and 49° West from AES maps for the years 1971-1988. Based on the statistical data gathered, a rough estimate of the downtime for different limiting sea ice concentrations was made. The actual downtime associated with sea ice will depend on the operating procedure adopted.

Structural Analysis

Local finite element structural analysis was performed on a column wall of the NEKTON 8000 FPV in an effort to obtain an understanding of the capability of the preliminary design of the structure to resist the high pressures associated with an impact of an iceform with the vessel. Various pressure values and contact areas were investigated to obtain an order of magnitude of the limiting impact scenarios which could be withstood by the column as it is designed today. The analysis was exclusively static. No attempt was made to incorporate the dynamic effect of ice loading or column response.

The results of the analysis illustrated that the structural response under the effect of sheet ice loading remains within the limits of serviceability limit state (SLS) design.

Under a loading scenario of 2 MPa on an area of 42 m^2 the structural response of the column wall remained within the limits of ultimate limit state (ULS) concrete design. Statically, this loading scenario represents an impact of 82 MN. Based on work completed by C-CORE, this force represents a peak collision force having a return period of approximately 940 years.

Figure 10 illustrates a typical deflection pattern of the column wall under an example loading.

Under the loading scenario which represents the 190 MN accidental design load as specified by C-CORE the column wall experienced localized structural damage when analyzed statically. This loading scenario requires further analysis work, particularly with respect to the role of dynamics in both the applied ice pressure and the structural response. The high impact pressure associated with this loading occurs as impulse loading and thus the relatively short time duration over which it is applied will have a significant effect on the response of the column wall.

The final design of the structure will depend on the statutory requirements which may be imposed with respect to accidental ice loading.

It is important to realize that with further refinement to the iceberg detection and collision force calculation models developed by C-CORE, (i.e. increased radar efficiency, inclusion of impact eccentricity, etc.), the return periods associated with the impact loads discussed above would increase.

CONSTRUCTION

Various construction methods were studied during the development program with emphasis on local infrastructure, available manpower resources and the associated construction and site development cost.

A construction method was selected based on the above considerations and four possible construction sites were identified ont he Avalon Peninsula, including an area within the industrial development zone at Argentia.

The site requirements consist of a flat surface area of approximately 5 hectares, a quay wall with a minimum 7 metres water depth, as well as availability of a warehouse/work shop and offices. The site should be in a sheltered position and enable direct access to the open sea.

The first phase of the selected construction method involves the construction of the concrete ring pontoon and the start of the six columns to a height of 1 metre. This activity would be executed on a skidway system. During this phase, hull outfitting is commenced. The completed ring pontoon is skidded onto two transport barges, towed to a deep water site and floated free by ballasting the transport barges. (See Figure 11).

The ring pontoon is towed back to the quay for the second phase of the construction method, which includes the completion of the six columns by slipforming and also, the completion of the hull outfitting. During this activity, the hull is ballasted down on a prepared level surface and concreting of the three quay side columns completed. The hull is then deballasted, rotated and re-ballasted down for completion of the remaining three columns. (See Figure 12).

After completion of the second phase of the hull construction, the hull is ready for mating to the steel deck structure.

The conventional design of the steel deck structure allows for it's construction to be executed as one unit in one fabrication yard, or alternately, in up to fifteen "pancakes" units at various fabrication yard locations, for final assembly and pre-commissioning at an assembly site. (See Figure 13).

If the second alternative is chosen, the completed "pancakes" could be transported to the hull construction site and assembly would take place on the skidway system in parallel with the second phase of the hull construction.

For either alternative, the completed and pre-commissioned steel deck structure is loaded onto a transport barge for mating with the concrete hull.

The mating operation would be carried out at a deep water site by positioning the transport barge supporting the deck structure between the hull columns, followed by controlled deballasting of the hull. (See Figure 14).

After connection of the hull to the deck structure's transition rings, the transport barge is removed, hook-up operations completed, the vessel commissioned and readied for tow-out to the production site.

Various project schedules have been prepared and for each, the critical path runs through the design, procurement and fabrication activities related to the process facilities. From these schedules it was determined that a concrete hull semi-submersible could be built within the same time frame as a comparable steel hull semi-submersible.

Detailed cost estimates were prepared for the construction of the NEKTON 8000 FPV concrete hull on an existing Avalon Peninsula construction site, together with preliminary cost estimates for the vessel systems.

In order to determine the economic viability of a concrete hull semi-submersible and to justify further development expenditures with the ultimate objective of providing a cost effective vessel for operation on the Grand Banks, cost comparison estimates with steel hull semi-submersibles were completed. In addition to the vessel cost, factors such as maintenance, operating efficiency, safety, etc. are important considerations in the cost equation. The cost matrix below summarizes our conclusions.

CONCRETE HULL VS STEEL HULL SEMISUBMERSIBLES

Cost Factor		Negative	Equal	Positive
Hull	:			X
Vessel Systems	:	X		
Deck Structure: Process Facilities, Services, Accommodations	:		X	
Maintenance	:			X
Operating Efficiency	:			X
Safety	:			X
Local Benefits	:			X

CONCLUSION

Based on the preliminary results of the development program, the conclusion is that concrete hull semi-submersibles offer a practical and cost efficient option for the recovery of hydrocarbon reserves from the Grand Banks of Newfoundland.

We remain firmly committed to our objective of providing a vessel that can meet the highest standards with respect to the safety of personnel and the environment, whilst assuring the maximum industrial benefits to Newfoundland and Canada.

ACKNOWLEDGEMENTS

The authors are grateful for the financial assistance provided by the Canada/Newfoundland Offshore Development Fund and the cooperation and guidance received from the Department of Development and Tourism, the Department of Energy, and the Department of Career Development and Advanced Studies, Government of Newfoundland and Labrador.

REFERENCES

"Terra Nova Development - Concrete Semi-Submersible Design Study - Design Requirements", Petro Canada, March 1988.

Jordaan, I.J.: "Safety Levels Implied in Offshore Structural Design Codes: Application to CSA Program for Offshore Structures", February 1988, Revised September 1988.

Germain, G.C. et al: "Concrete Floating Production Vessel for the East Coast of Canada - NEKTON 8000 FPV", Paper presented at the Marine Associated Services Technology Systems Conference, Halifax, Nova Scotia, October 1987.

Valenchon, C.P. et al: "The Concrete Floater NEKTON 8000 - An Interesting Alternative for Offshore Newfoundland" Paper presented at Offshore Newfoundland, June 1987.

Valenchon, C.P. et al: "The Concrete Floating Production Platform NEKTON 8000 FPV", proceedings of the 6th International Symposium on Offshore Mechanics and Arctic Engineering, Houston, March 1987.

"Hibernia Development Project: Environmental Impact Statement", Mobil Oil Canada Ltd, May 1985.

Hoff, G.C.: "The Challenge of Offshore Concrete Structures", ACI, Concrete International, August 1985.

Hoff, G.C.: "The Service Record of Concrete Offshore Platforms in the North Sea", International Workshop on Concrete for Offshore Structures, St. John's, Newfoundland.

Sparks, C.P. et al: "PLTB 1000: A Concrete Tension Leg Platform", proceedings of the 4th International Symposium on Offshore Mechanics and Arctic Engineering, Dallas, February 1985.

"Offshore Concrete Structures in the Arctic", ACI Committee, 357.

Fotinos, G.C., Gerwick, B.C.M. and Hsu, Y.Y.: "Durability of Concrete in the Arctic Environment", proceedings of the FIP/CPCI Symposia, Calgary, Canada, August 1984.

"State of the Art Report on High Strength Concrete", ACI Journal, July-August 1984.

"Mobile Drilling Platforms", regulations by NMD.

Pettenati-Auziere, C.: "Flexible Dynamic Risers - State of the Art", The Way Forward for Floating Production Systems, London, December 1985.

"Mobile Offshore Units - Position Mooring", DNV Rules.

FIGURE 1

ELEVATION OF THE NEKTON 8000 FPV

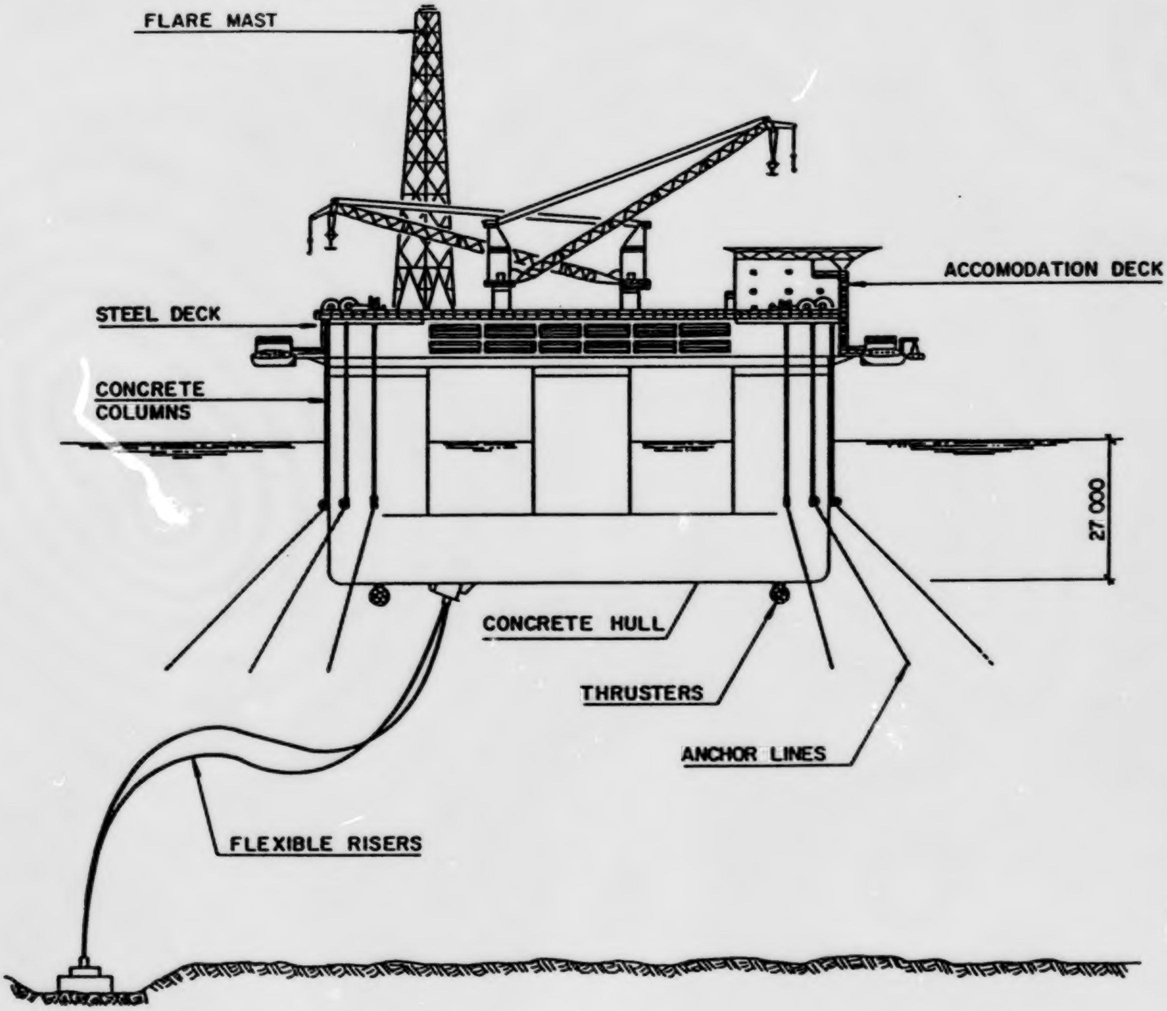

FLARE MAST
ACCOMODATION DECK
STEEL DECK
CONCRETE COLUMNS
27 000
CONCRETE HULL
THRUSTERS
ANCHOR LINES
FLEXIBLE RISERS

FIGURE 2

NEKTON 8000 FPV - MAIN CHARACTERISTICS

Main Dimensions

HULL:

- length (overall)	94.0 m
- beam (overall)	80.0 m
- height, keel to main deck	50.5 m
- height, keel to lower deck	41.0 m

PONTOON SECTION:

- width	18.0 m
- height	13.0 m

COLUMN DIAMETER:	18.0 m

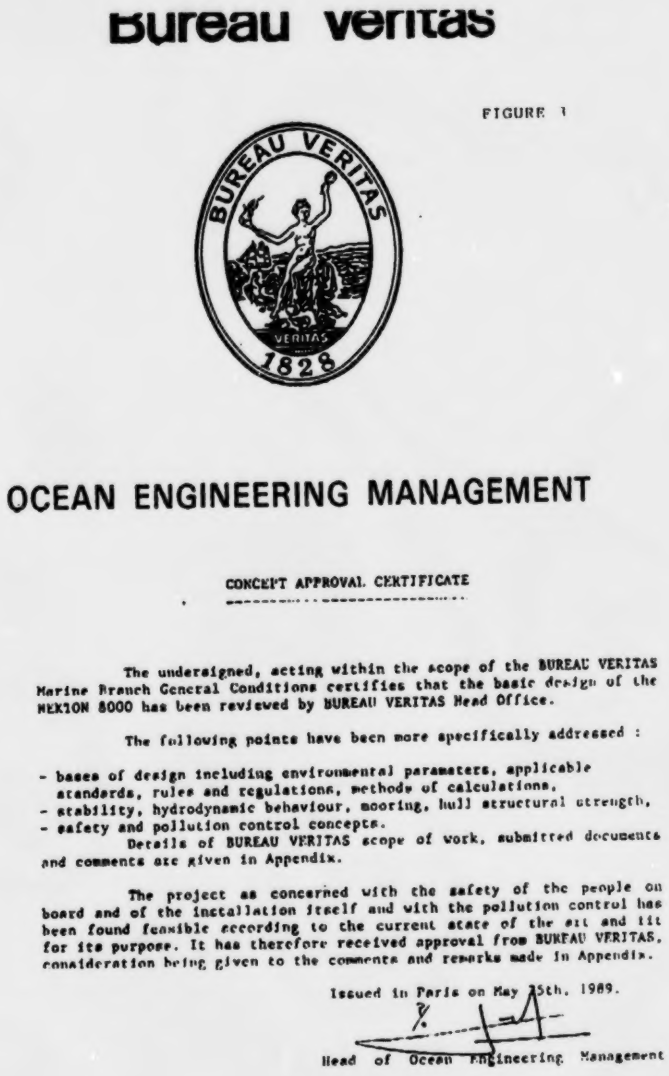
DECK AREA:

- one level	7,450 m^2

Drafts and Displacements

Transit Draft	12.7 m
Air gap	28.3 m
Displacement	63,500 tonnes
Operating Draft	27.0 m
Air gap	14.0 m
Displacement	86,800 tonnes

Deck Carrying Capacity (excl. deck structure) at operational draft	11,775 tonnes
Crude Oil Storage Capacity (optional)	140,000 bbls
Concrete Volume	17,100 m^3



Bureau Veritas

FIGURE 1

OCEAN ENGINEERING MANAGEMENT

CONCEPT APPROVAL CERTIFICATE

The undersigned, acting within the scope of the BUREAU VERITAS Marine Branch General Conditions certifies that the basic design of the NEKTON 8000 has been reviewed by BUREAU VERITAS Head Office.

The following points have been more specifically addressed :

- bases of design including environmental parameters, applicable standards, rules and regulations, methods of calculations,
- stability, hydrodynamic behaviour, mooring, hull structural strength,
- safety and pollution control concepts.

Details of BUREAU VERITAS scope of work, submitted documents and comments are given in Appendix.

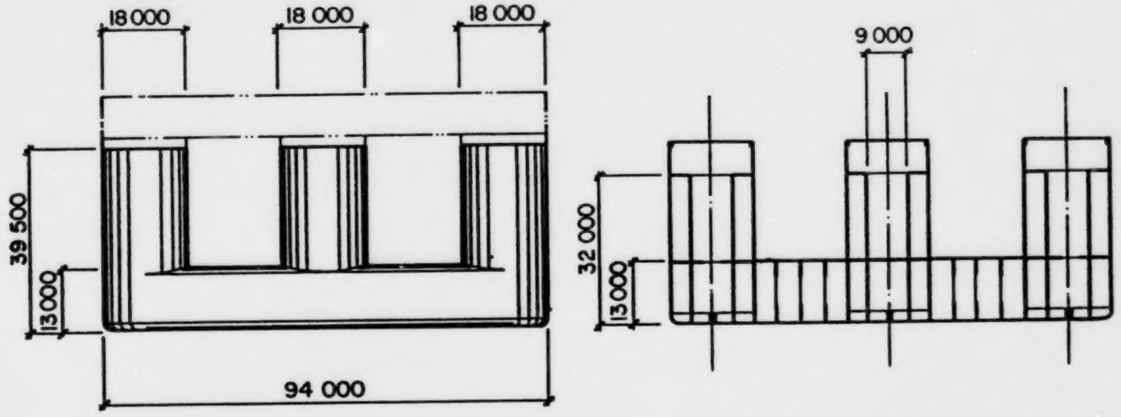
The project as concerned with the safety of the people on board and of the installation itself and with the pollution control has been found feasible according to the current state of the art and fit for its purpose. It has therefore received approval from BUREAU VERITAS, consideration being given to the comments and remarks made in Appendix.

Issued in Paris on May 25th, 1989.

Head of Ocean Engineering Management

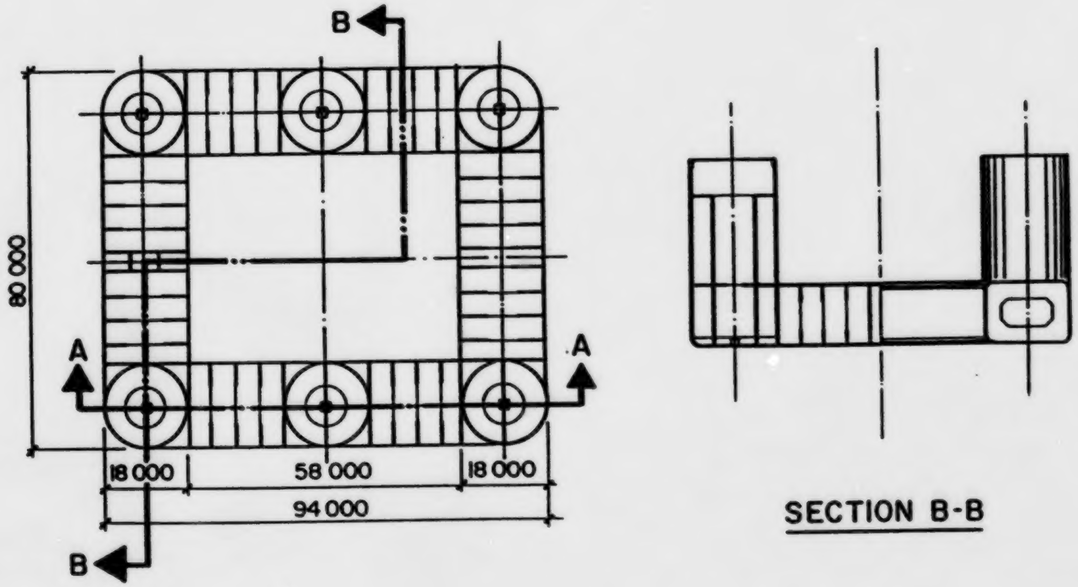
FIGURE 4

CONCRETE HULL DETAILS


18 000
18 000
18 000
39 500
13 000
94 000
9 000
32 000
13 000

ELEVATION

SECTION A-A


B
A
A
80 000
18 000
58 000
18 000
94 000
B

SECTION B-B

PLAN
SECTION THROUGH PONTOON

FIGURE 5

PLAN VIEW OF DECK STRUCTURE

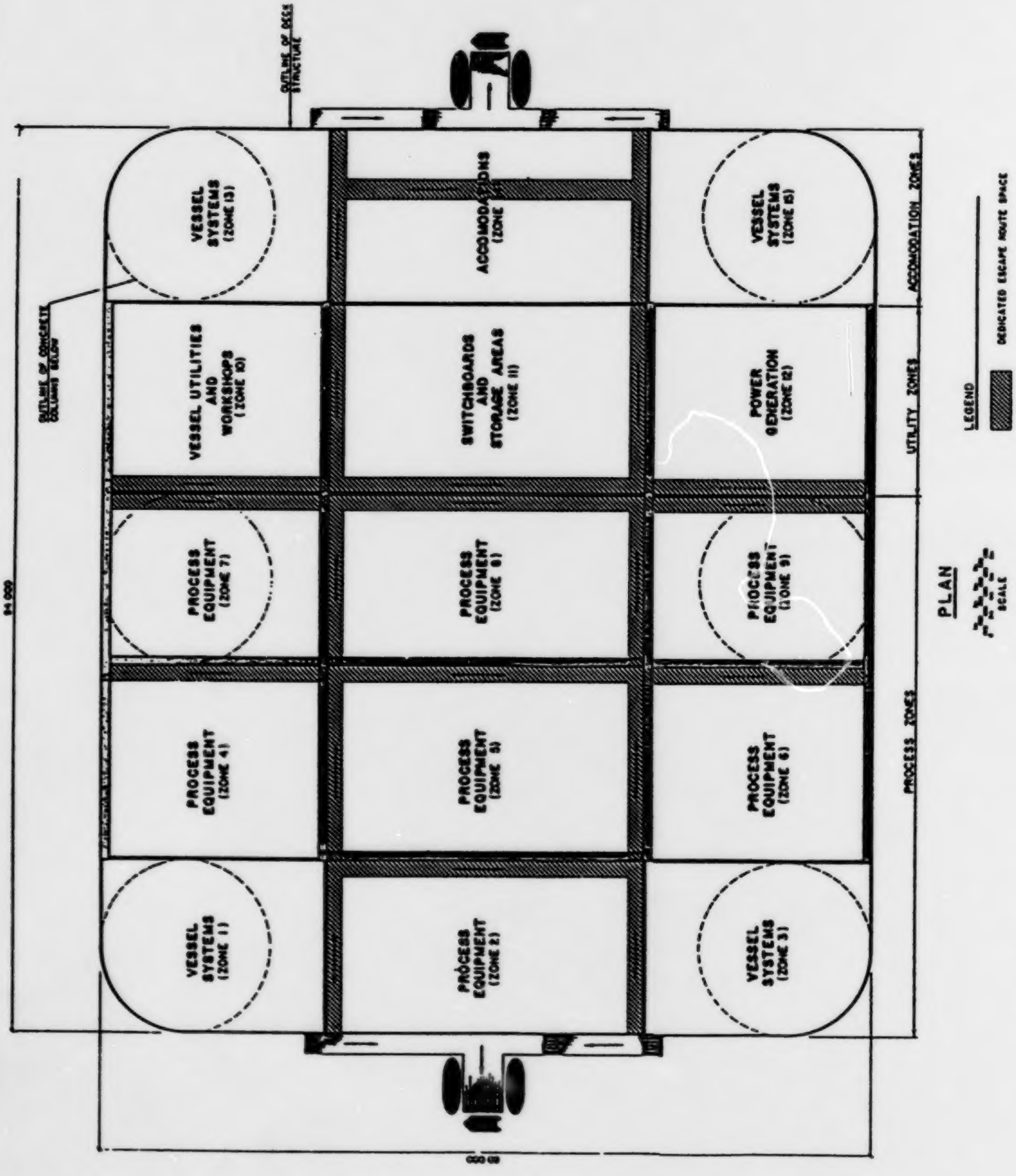

OUTLINE OF DECK STRUCTURE
OUTLINE OF CONCRETE COLUMNS BELOW
84 000
VESSEL SYSTEMS (ZONE 13)
ACCOMODATIONS (ZONE 14)
VESSEL SYSTEMS (ZONE 15)
VESSEL UTILITIES AND WORKSHOPS (ZONE 10)
SWITCHBOARDS AND STORAGE AREAS (ZONE 11)
POWER GENERATION (ZONE 12)
PROCESS EQUIPMENT (ZONE 7)
PROCESS EQUIPMENT (ZONE 8)
PROCESS EQUIPMENT (ZONE 9)
PROCESS EQUIPMENT (ZONE 4)
PROCESS EQUIPMENT (ZONE 5)
PROCESS EQUIPMENT (ZONE 6)
VESSEL SYSTEMS (ZONE 1)
PROCESS EQUIPMENT (ZONE 2)
VESSEL SYSTEMS (ZONE 3)
ACCOMODATION ZONES
UTILITY ZONES
PROCESS ZONES
LEGEND
DEDICATED ESCAPE ROUTE SPACE
TRUSS BEAM
BULKHEAD
EXTERIOR ESCAPE ROUTES
PLAN
SCALE

FIGURE 6

ENVIRONMENTAL PARAMETERS FOR HYDRODYNAMIC MODEL TESTING

IRREGULAR WAVES

Parameter	One-Year Spectrum		100-Year Spectrum	
	Target	Actual	Target	Actual
H 1/3 (m)	10.3	10.319	15.9	15.69
Tp (sec)	12.5	12.23	17.9	16.837
H max (m)	21.0	22.895	23.9	30.133

WIND SPECTRA

Parameter	One-Year Wind		100-Year Wind	
Extreme Average Velocities (m/s)	Target	Actual	Target	Actual
1 hour	23.2	26.05	34.5	34.63
1 min	30.0	28.59	42.3	36.80
3 sec	33.2	33.43	49.3	41.94

CURRENT

	Target Average Speed (m/sec)	Actual Average Speed (m/sec)
one year	1.00	1.05
100 year	1.25	1.21

FIGURE 7

COMPARISON OF SAMPLE RESULTS

GLOBAL LOADS

Heading	0 deg.	45 deg.		90 deg.
Global Loads (KN)	Fx	Fx	Fy	Fy
Calculated operational	3488	3559	3151	5155
Measured operational	2760	3190	4000	4260

DYNAMIC BEHAVIOR

	Mean Value	Standard Deviation	Maximum Value
Sway Measured	3.9 m	3.2 m	21.2 m
Sway Calculated	4.7 m	4.6 m	25.1 m
Heave Measured	0.0 m	0.95 m	4.3 m
Heave Calculated	0.0 m	1.1 m	3.2 m
Roll Measured	0.3 deg	1.0 deg	4.1 deg
Roll Calculated	0.5 deg	1.0 deg	3.3 deg
Tension 9 Measured	1638 KN	728 KN	5000* KN
Tension 9 Calculated	1856 KN	740 KN	5998 KN

*estimated

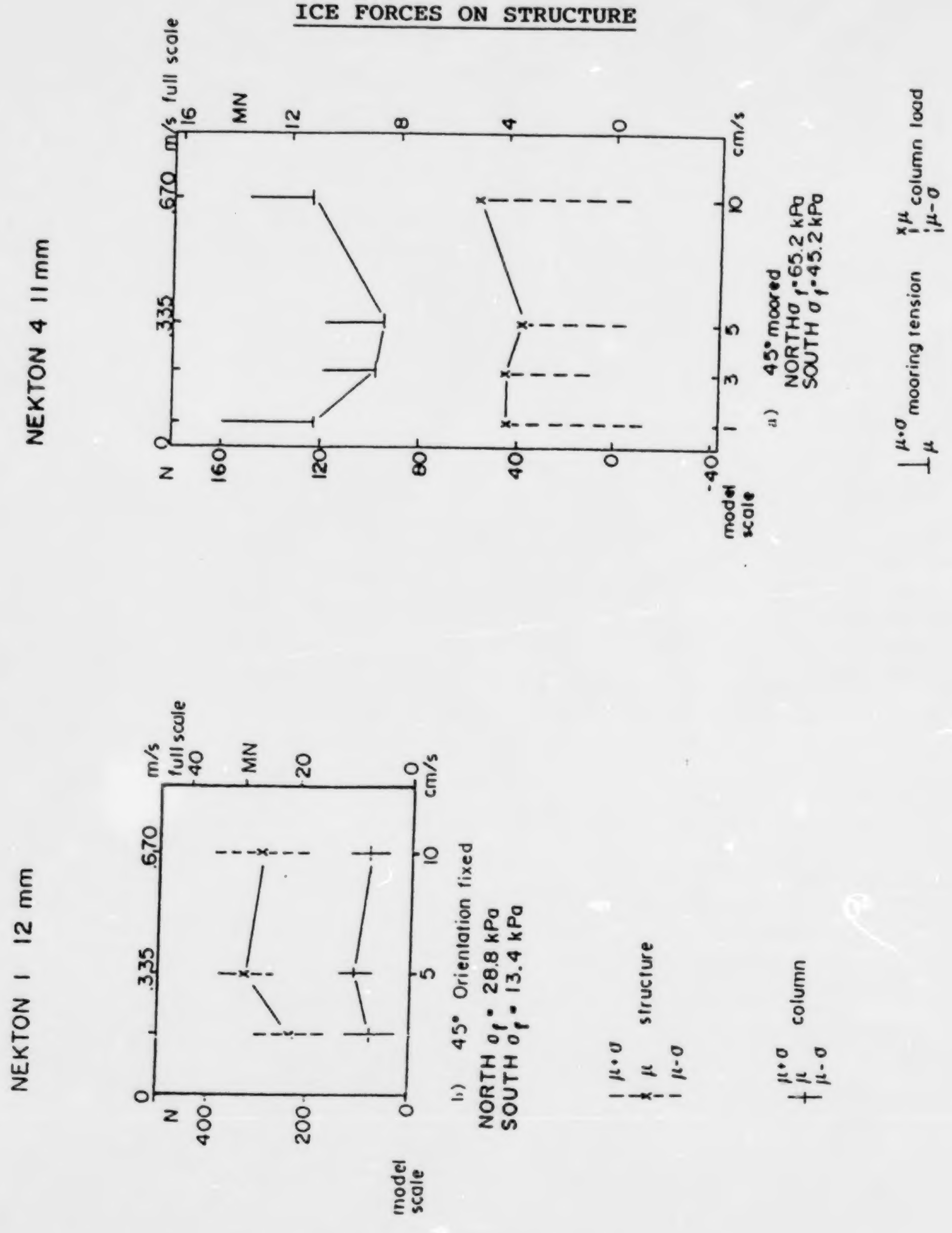
FIGURE 8

ICE ENVIRONMENTAL PARAMETERS

Maximum geographical extent of sea ice	44°N Latitude
Average concentration of sea ice (when present)	7/10
Average ice floe size on Grand Banks	10 - 20 m
Average undeformed first year ice thickness	20 - 100 cm
Average rafter first year ice thickness	2.7 - 4 m
Maximum undeformed first year ice thickness	2 m
Average drift speed for sea ice	0.26 m/s
Maximum drift speed for sea ice	0.9 m/s
Mean unconfined compressive strength for first year ice (flaking test)	3.59 - 6.79 MPa
Mean unconfined compressive strength for first year ice (borehole jack test)	8.29 - 16.15 MPa
Major iceberg season	March - July
Average distribution of icebergs on Grand Banks	Growlers - 20% Small bergs - 39% Medium bergs - 30% Large bergs - 11%
Mean drift velocity of icebergs	0.35 m/s
Maximum drift velocity of icebergs	1.36 m/s
Density of iceberg ice at -5°C	0.9 to 0.915 g/cm^3
Grain size of iceberg ice at -5°C	3 - 15 mm
Uniaxial compressive strength of iceberg ice at -5°C and strain rate of 10^{-3}/sec	5.2 - 7.4 MPa

FIGURE 9

ICE FORCES ON STRUCTURE



a) 45° moored
NORTH σ_f = 65.2 kPa
SOUTH σ_f = 45.2 kPa

$\mu+\sigma$, μ mooring tension
$\times\mu$, $\mu-\sigma$ column load

b) 45° Orientation fixed
NORTH σ_f = 28.8 kPa
SOUTH σ_f = 13.4 kPa

$\mu+\sigma$, μ, $\mu-\sigma$ structure

$\mu+\sigma$, μ, $\mu-\sigma$ column

FIGURE 10

TYPICAL DEFLECTION PATTERN

Load Case: 2 MPa on 42 m^2

Magnification Factor = 76

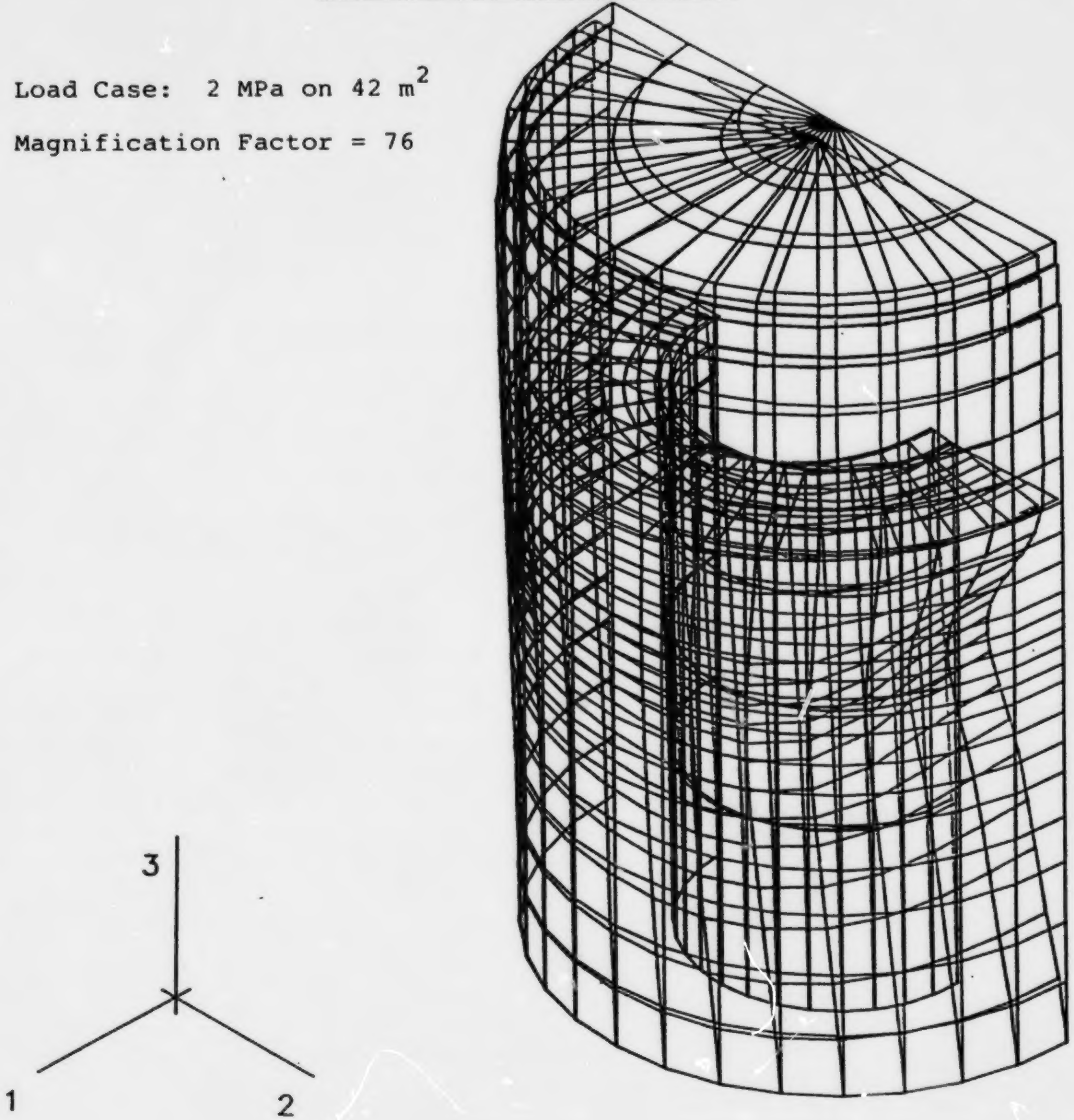
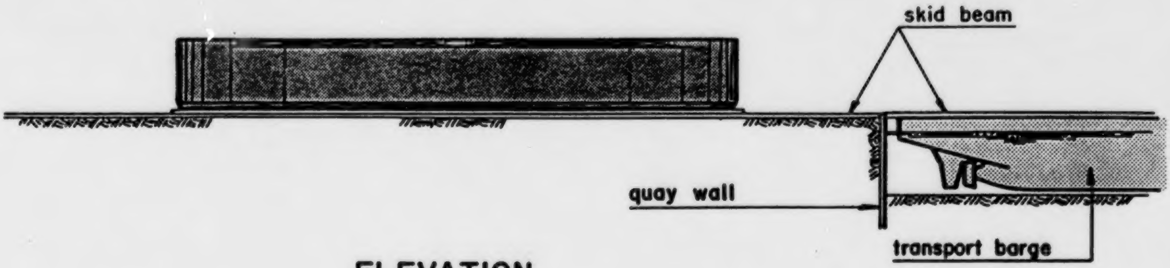
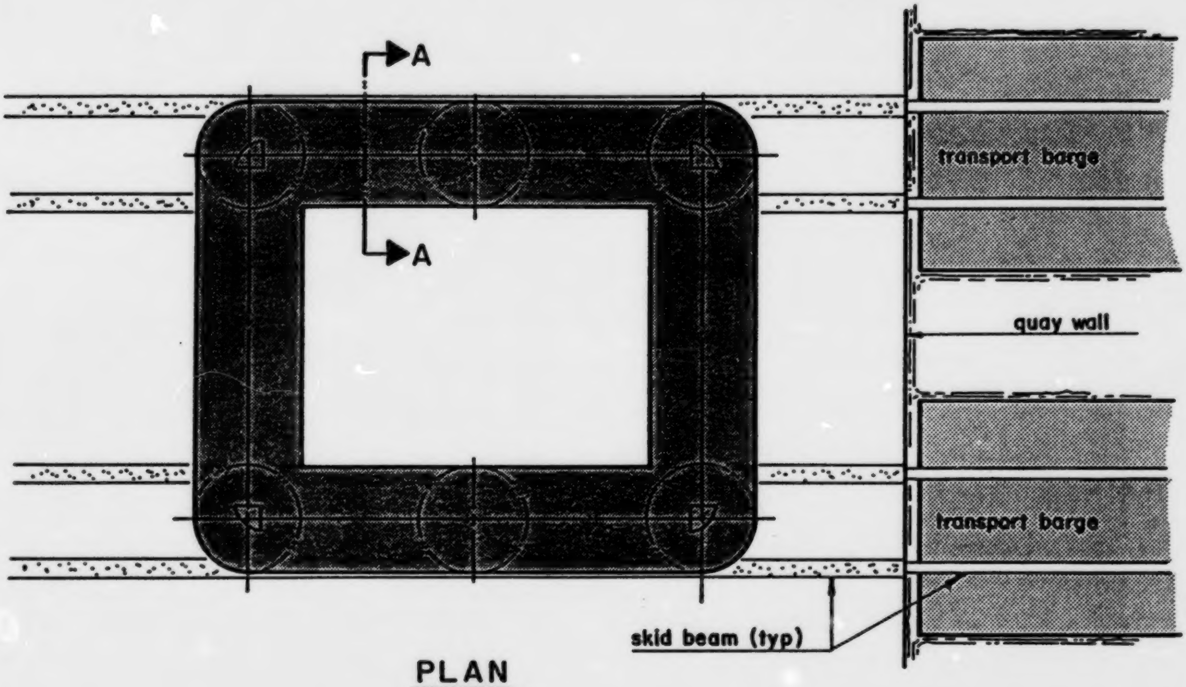


FIGURE 11

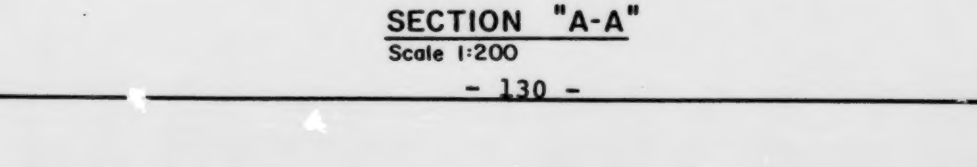
Construction of the Ring Pontoon on a Skidway System


skid beam
quay wall
transport barge

ELEVATION
Scale 1:1000


A
A
transport barge
quay wall
transport barge
skid beam (typ)

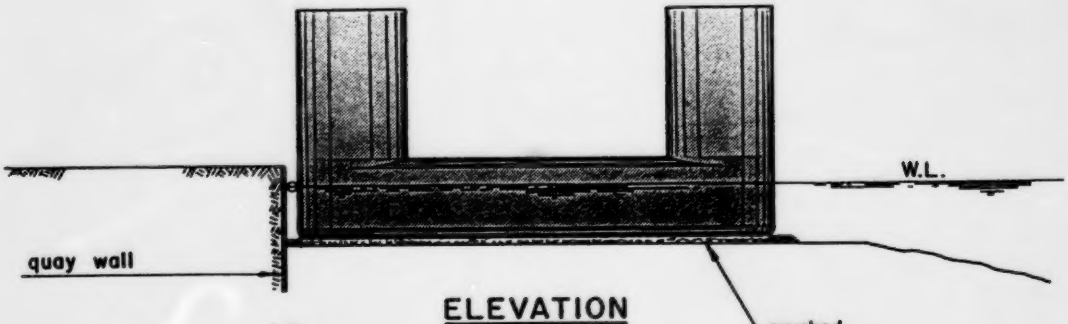
PLAN
Scale 1:1000


skid beam
Pontoon
16 000

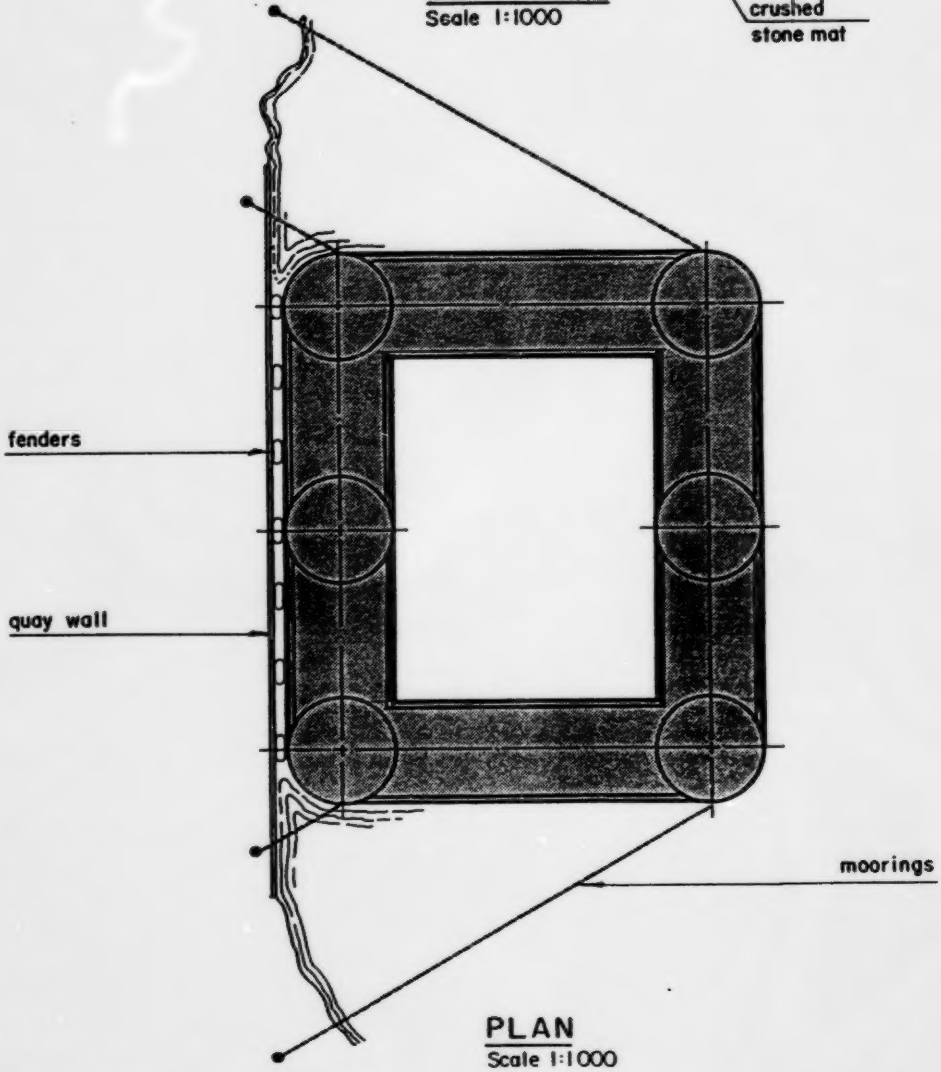
SECTION "A-A"
Scale 1:200

FIGURE 12

Construction Along Side a Quay


W.L.
quay wall
crushed stone mat

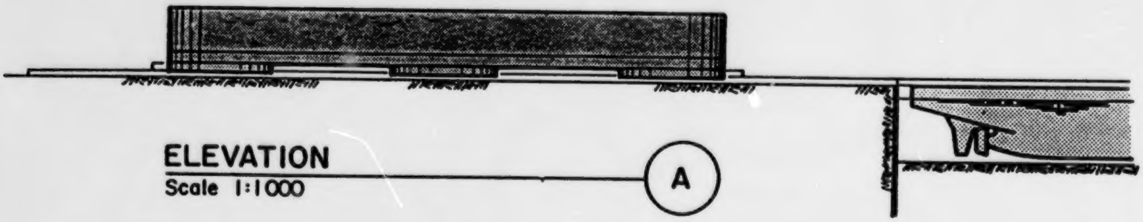
ELEVATION
Scale 1:1000


fenders
quay wall
moorings

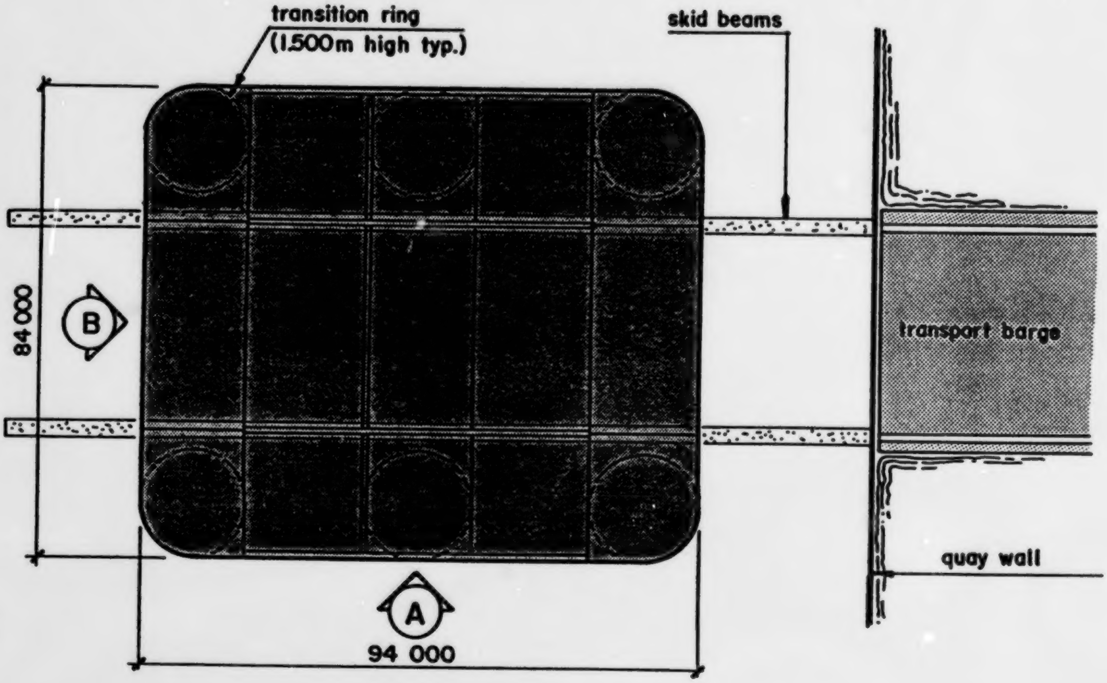
PLAN
Scale 1:1000

FIGURE 13

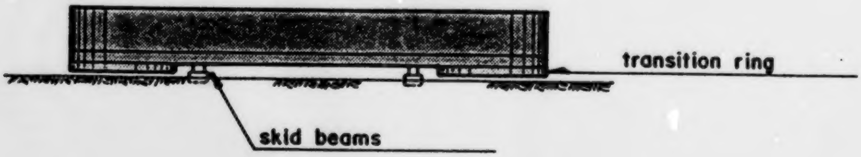
Deck Assembly Site



ELEVATION A
Scale 1:1000


transition ring
(1.500m high typ.)
skid beams
84 000
B
transport barge
quay wall
A
94 000

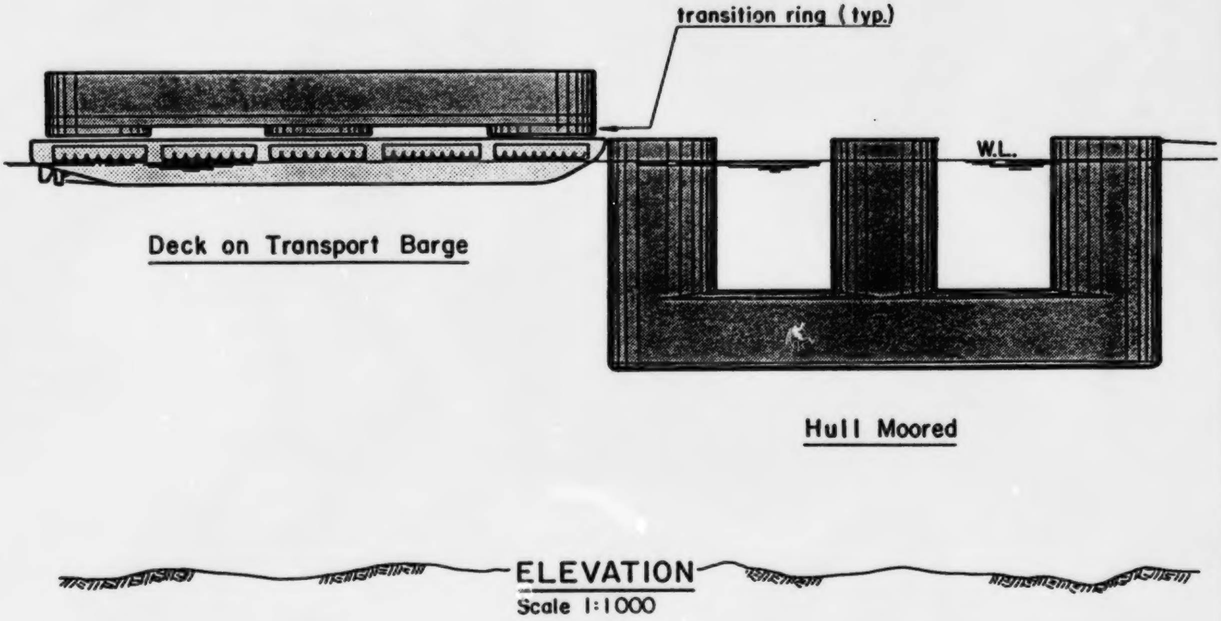
PLAN
Scale 1:1000

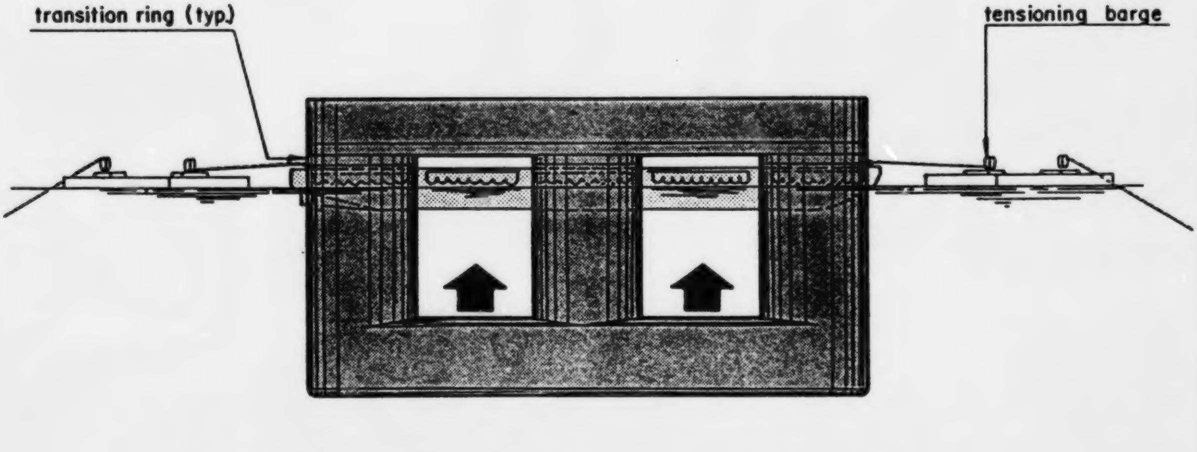

transition ring
skid beams

ELEVATION B
Scale 1:1000

FIGURE 14

Deck to Hull Mating


transition ring (typ.)
W.L.
Deck on Transport Barge
Hull Moored
ELEVATION
Scale 1:1000


transition ring (typ.)
tensioning barge

Transfer of Deck from Barge to Hull by Deballasting of Hull

ELEVATION
Scale 1:1000

SPEAKERS : **CRAIG LANG AND BARRY RYAN**

COMPANY : **SEAWAYS ENGINEERING (UK) LTD.**

LOCATION : **LONDON, ENGLAND**

TOPIC : **A COST EFFECTIVE NEW BUILD SEMI-SUBMERSIBLE**

BIOGRAPHY: Mr. Lang graduated with a B.Sc(Eng) from London University 1963 and has the following training: Professional Professional Engineer's Licence, Registered Colorado, U.S.A. Student Apprenticeship with Babcock, Wilcox Limited, Renfrew. Craft Apprenticehsip (Engine Fitter) Barclay Curle & Company, Glasgow. Ordinary National Certificate (Distinction), Stowe College, Glasgow (Top Apprentice Award).

Mr. Lang has worked on a number of projects: Project Engineer for vessel and moorings for Balmoral FPV; Site Representative for Dome's Sovereign Explorer; Staff Engineering for Tension Leg System on Conoco's Tension Leg Platform; Project Management Team for Thistle "A"; Project Engineer for Hughes Glomar Explorer.

BIOGRAPHY: Mr. Ryan is a Senior Project Management Engineer with over twenty years in the heavy engineering and offshore petrochemical industries. He has extensive experience in the design and construction of offshore floating production facilities and has worked on offshore projects in Singapore, Brunei, Sweden and Norway, including fixed platforms and tanker conversion.

Mr. Ryan was the Senior Representative of Sun Oil in GVA yard during the design and construction of Balmoral; Project Engineer for BP on the Buchan Field; Project Engineer working in conjunction with Conoco on the Hutton TLP; and Senior Project Engineer - Cormorant Alpha.

1.0 INTRODUCTION

Personal experience of design, construction and operation of ships and semi-submersibles, has convinced Seaways Engineering that existing semi-submersibles are unnecessarily complex and expensive and that new semis could easily be designed to exploit the traditional shipyard practices used so successfully for so long for many different types of vessel.

Because designers have not exploited the benefits of 'shipyard friendly' designs many shipyards have been unable to be cost effective and have had 'control' systems imposed on them by Clients. These control systems involve the creation and application of ever more detailed 'fabrication specifications' requiring 'expert', on-site interpretation and implementation. As a direct result of this approach, every job has tended to become a development contract, incurring huge increases in cost and construction time with little regard for what was an adequate solution for the task in hand.

Whilst the industry enjoyed the high profit margins of the oil-boom years, there was no incentive or mechanism whereby this trend could be reversed. The suggestions of a few 'marine oriented' designers, that alternative solutions would prove both easier and less expensive to implement, went unheeded. Investors continued to fund projects based on 'known' (ie. oilpatch) design technology and construction techniques. Eventually, billion dollar fundings became both common and accepted as the inevitable price of offshore projects.

The collapse of oil prices, combined with the need to develop smaller, less profitable, offshore oil fields, changed this scene dramatically. The cost of servicing and recovering capital investments became a substantial element in the profit and loss account and even operating costs became of interest. The search for less expensive development and production facilities and lower operating costs assumed far greater importance and 'novel' proposals were no longer dismissed without real consideration and careful evaluation.

Included in these alternative proposals was the use of floating platforms, a concept pioneered by Hamilton Brothers for the small inshore Argyll field. Using a converted semi-submersible drilling rig, a subsea production system and flexible risers, this had successfully supported a highly profitable production operation over several years. Other operators have followed this route using second hand exploration semis which were readily available at extremely low prices. Unfortunately, many purchasers grossly under-estimated conversion costs.

To avoid the unpredictable element in conversion the Balmoral project selected a custom built unit. As initially conceived the system was to be capable virtually 'all-singing, all-dancing' with drilling and workover, saturation diving, manoeuvring over the template wells, etc., etc., and the budget was exceeded, eventually reaching £420 million. Developments since then have tended to simplify the approach in many ways, subcontracting diving and workover for example, enabling fewer people to do the job with less equipment.

Those 'floater' designers who did explore shipyard friendly designs retained the now traditional circular columns because of a 'feeling' that adverse hydrodynamic effects would result from square columns, including wave climb to the deck, excessive drag on the chains and so on. This mixture of tubulars and girders led to structural nightmares which were, and still are, totally alien to normal shipyard practice. None, hitherto, have proposed a purpose-built semi-submersible platform buoy which takes full advantage of both the very substantial benefits of being permanently anchored (rather than being a 'temporarily moored' mobile drilling rig) and of the low unit material and fabrication costs available from flat plate, panel lines and sub-arc welding.

2.0 DESIGN CONCEPT

Recognising the potential of the approach, Seaways Engineering embarked on the design of an ultra-simple vessel which, whilst being cheap to produce, would satisfactorily meet all safety and performance requirements, would be quick and easy to build and economical to operate and maintain. (Ref. figures 1,2&3 MPSS Drawings.)

The design utilises pre-fabricated high strength steel box girders assembled into an integrated structure. Builders use only the techniques and equipment already installed in shipyards for the construction of large tankers and only welding procedures and specifications and equipment familiar to shipbuilders are used.

This approach to rapid, low unit cost, marine construction is not new, being common practice for ships and bridges all over the world.

Thus, the present design is new only in the sense that it applies commonly used shipbuilding technology to semi-submersibles.

2.1 Structural Concepts

The concept is to create a structure composed entirely of twelve box girders (four pontoons, four columns and four 'deck bridges'). These extend throughout the vessel creating a fully integrated, ring framed box. This structure exhibits immense strength and employs the steel in a highly efficient manner. (See Figures 3 & 4). The continuity of the structure can be followed along the deck, down the columns and through the pontoons. All structure, including shell plate, stiffeners and stringers, is continuous, (there are no discontinuities in the primary structure) providing an immensely strong, highly efficient, simply constructed and cost efficient vessel.

This design has the major advantage of reflecting what has been shipyard practice for many years.

The structure, including the connections between the columns and the deck and pontoons has been extensively analysed by the designers, by independent design consultants Atkins Oil & Gas, and by the certifying authority Lloyds Register, and the strength and fatigue life fully satisfy all regulatory requirements. An example of the input, wave occurrences and fatigue lives is given. (See Figures 5 & 6.)

For this distribution, the minimum fatigue life is fifty-eight years, occurring within the pontoon at its connection to the column.

Material will be BS4360 Grade 50D. This is an excellent quality of steel with guaranteed properties. Its use does not introduce any special welding techniques since the maximum thickness used is only 26mm.

3.0 HYDRODYNAMIC ANALYSIS

A hydrodynamic analysis of the vessel in operating condition was performed in order to provide the distribution of hydrodynamic and hydrostatic forces on the vessel hull in waves of different period for subsequent structural analysis. Wave drift forces and vessel motions were also calculated for use in mooring analysis.

3.1 Analysis Method

The hydrodynamic analysis was performed using the Atkins ES AQWA-LINE programme. This is a three-dimensional radiation/diffraction programme.

The programme requires that the wetted surface of the hull be modelled by a finite element mesh as shown in Figure 7. A total of 804 elements were used which is sufficient to provide a good representation of the distributed hydrodynamic forces on the vessel.

3.2 Hydrodynamic Analysis Data

The properties of the vessel at operating draught are shown in Figure 10.

It is assumed that the wave frequency vessel response is unaffected by stiffness of the mooring lines which was confirmed by the model tests. An estimated static vertical component of mooring line tension of 600 tonnes is included in the vessel displacement.

Analysis was performed for wave incidence directions of 0, 22.5 and 45 degrees and wave periods of 5.98, 6.66, 7.52, 8.62, 10.12, 12.22, 15.44 and 20.94 seconds.

3.3 Hydrodynamic Results

As an example of the results, Figure 8 shows the response amplitude operators for surge, heave and pitch for waves incident on the beam.

The natural periods of roll, pitch and heave, including calculated added mass and inertia, are shown in Figure 9.

The hydrostatic and hydrodynamic loads on the structure are stored in the form of computer files which are used in the structural analysis of the vessel.

4.0 STABILITY

Calculation of the intact stability properties of the vessel shows that the vessel centre of gravity for operating and transient conditions for the proposed operating configuration, ie. 10,000 tonnes with a centre of gravity 5m above the main deck is well within the safe operating region as defined by Lloyds' Rules and all other certifying authorities.

The damage stability characteristics of the vessel also comply with Lloyds' Rules. Sub-division of the vessel is such that two compartment damage, at the waterline in a 50 knot wind, causes the vessel to list by approximately 9.5 degrees with no downflooding point (assumed at main deck level) closer than 16.9m to still water line. (Figures 11, 12, 13, 14, 15, 16 & 17.)

5.0 MOORINGS

5.1 Method of Analysis

The proposed mooring system was investigated using quasi-static analysis and the Atkins ES mooring programme AQWA-LIBRIUM. The programme has the facility to model elastic catenary lines, the properties of which are stored in database form and interpolated.

The quasi-static mooring analysis procedure is as follows:

1. Compute total steady wind, current and wave drift force.

2. Calculate vessel mean offset position due to steady forces.

3. Add peak wave frequency motion to steady offset to obtain peak offset position at which peak line tensions are evaluated.

   i.e. the offset includes static and dynamic components.

The peak wave frequency offset is obtained by factoring the significant offset calculated by the Atkins ES AQWA-FER spectral analysis programme which combines the hydrodynamic analysis motion results with the extreme wave spectrum using conventional spectral theory.

To investigate the damage condition, each mooring line is removed in turn to identify which line breakage causes the highest tension in the remaining lines. The peak wave frequency motion is added to the steady offset so obtained and tensions in the lines evaluated. (Figures 18, 19, 20, 21 & 22.)

6.0 MODEL TESTING PROGRAMME

Tests were conducted initially at Weatherstone's Offshore Laboratory, and subsequently at Glasgow University under the direction of Professor D. Faulkner and Dr. A. Incecik. Two models were used, one for hydrodynamic investigations and one for structural investigations. Both were 1:100 scale and equipped with the full payload of 10,000te on the main deck. The model testing programme was preceded by extremely detailed analysis during which the static and hydrodynamic behaviour of the model was predicted. Subsequent analysis of the test tank results demonstrated close agreement with these predictions and fully confirmed the viability of the proposed basic design concept. The testing at Glasgow University was exhaustive and more than 500 test runs were made on the two fully instrumented models for a variety of headings and a wide spectrum of sea states for both the intact and damaged conditions.

The possibility of **SINGLE DRAUGHT OPERATION** was thoroughly investigated and confirmed as feasible. This is a major advantage of this design since production can continue in weather which will force other semis to stop producing, to raise the vessel to avoid wave slam.

N.B. Semis commonly have both an operating and a survival draught to maximise payload. It is usually necessary to stop operations in heavy seas to deballast and rise to survival draught. This can be a hazardous operation and since the Ocean Ranger must be done by qualified personnel. **Single draught operation is obviously an extremely desirable safety feature.**

The structural model, 1:100 scale in 4mm PVC, has been instrumented with strain gauges and hydrodynamically tested at Glasgow University. Tests included grounding of one corner and along one edge. The data obtained showed that maximum principle stresses were well within the allowables throughout the structure.

Tests were conducted to investigate hydrodynamic behaviour at 27.5m, 19m and inspection/transit draught, 7.5m, for intact and damaged conditions. Environmental forces were calculated and superimposed on the model during testing, with a 10,000te payload at 5m above main deck in deck houses as shown in Figure 23. All strain gauge readings were recorded along with full video and photographic records. (Test reports from Glasgow University's Department of Naval Architecture and Ocean Engineering and from Weatherstones Offshore Laboratory are available.)

7.0 FABRICATION AND ASSEMBLY

The design utilises a shell plate thickness of 16mm virtually throughout. Some local thickening at deck/column and pontoon/column connections is required and there 26mm plate is introduced.

Prefabrication of the boxgirders can be performed on almost any site. They are easily transportable by ship or barge.

Tanker fabrication experience is particularly applicable to the proposed MPSS vessel. The stiffened flat plates will preferably be fabricated using a panel line assembly which can be either semi or fully automated. However, manual methods are entirely acceptable.

The stiffened plates can easily be laid out and erected into boxes with relatively light handling gear. The maximum weight of any plate with stiffeners is about 10 tonnes. The weight of a box will be approximately 40 tonnes. Some shipyards intend to lift one completely outfitted column, weighing about 800 tonnes, and install it as a single unit.

The protective paint (primer only) will be applied to the panels on a grit blast finish.

The design of the MPSS is also suitable for Developing and Third World countries. The individual activities and skills involved are within the capabilities of local craftsmen who would require the minimum of instruction and on-site training.

8.0 CONSTRUCTION FACILITIES

Construction can be done on a slip or in a large drydock. Normal shipyard skills are necessary. The craneage needs to be suitable to lift 80te up to 60m and outreach to 50m.

Discussions with the shipyards have revealed that they expect the build-time, for the first unit, to be about eighteen months. This would include the time for the preparation of the working drawings. Build-time for the second unit is estimated to be about nine to twelve months. It is estimated that fabrication and construction for yards with panel lines will be about 18 manhours per tonne. This compares extremely favourably with the times of 150-180 manhours per tonne, which is common for semis with tubular construction because of the complicated connections throughout.

9.0 OUTFITTING

Outfitting in the compartments is minimal. Compartments will be outfitted before erection. All outfitting and commissioning will be completed before the vessel leaves dock; a major advantage of all floaters.

10.0 TOWOUT

The possible methods of transporting the MPSS to site include towing by tugs and transportation by a heavy-lift vessel. Speeds are approximately 4 and 12 knots respectively.

11.0 OFFSHORE INSTALLATION

It is intended that installation of the MPSS on the site will be by a sub-contractor who will receive the unit at the end of tow (although he may also perform the tow-out).

Arriving on site, anchor handling tugs will retrieve pairs of diagonally opposite chains which will be passed to the pontoon deck for pre-tensioning. Windlasses and fairleaders can be provided if necessary. Chain pullers of about 50HP capacity will be sufficient for manoeuvring above a template for well workover. Safety considerations may dictate more powerful machinery if withdrawal from the area above the well is specified. The vessel now takes on ballast and water and is gradually lowered to a draught of 27.5 metres over a period of twelve hours. The Ballast Master monitors this activity carefully throughout and enters any untoward incident in the record. Ballast water enters through sea-chests at the corners of the pontoons.

A typical North Sea mooring spread would consist of twelve chain and anchor sets for a location in 150 metre water depth. The chains, which would be about 100-120mm diameter, and made from Grade 4 steel, or ORQ + 20%, would be some 1,100 - 1,400 metres in length. Each would use a drag embedment anchor of 15 to 25 tonnes. Pile anchoring was used on Balmoral but is expensive and not usually necessary unless soil is very poor.

12.0 RISER INSTALLATION

The risers can now be installed through a moonpool created by omitting boxes from the central deck area as required which is essentially structurally redundant. Outboard balconies are going out of favour in the North Sea due to the vulnerability of the risers in collisions, and legislation is expected prohibiting this arrangement.

13.0 PRODUCT STORAGE AND DISPATCH

Use of the MPSS as a production vessel may require the storage of dead crude. It is possible to store 30,000 tonnes of dead crude within a modified MPSS. Export will be by conventional methods.

Seaways Engineering are presently designing a modified MPSS exploiting the flat plate approach. This has internal storage for 180,000 tonnes of dead crude within the pontoons.

14.0 OPERATION AND MAINTENANCE

Hand-over of the vessel to the two man crew will follow a final check of the ballast and trim system, the condition of the structure and security of the moorings. Installation will then be complete and the planned functions of the vessel can commence.

Routine operation of the vessel is extremely simple, since it is designed to remain at one draught of 27.5m. There is never an occasion where it has to be taken up to a survival draught. Even in the worst anticipated sea-state, an adequate airspace will remain. The design has been model tested at 120' simulated wave height and no slamming of the underside of the deck occurred. It is anticipated that at least seven metres of air gap will be maintained.

When it is necessary to raise the platform to transit draught, the columns are gravity drained and the pontoons evacuated by compressed air.

For ballast control, including trim, a standard unit commonly employed for roll-on/roll-off ferries, and approved by the certifying authorities, will be used.

Only two persons are required to operate the MPSS, working alternate twelve hour shifts. Their duties are essentially confined to monitoring the ballast condition, the moorings and the general state of the vessel, and reporting to the Platform Superintendent. In certain operations it may prove possible to operate without a full-time crew, i.e. the vessel will be unmanned.

The benefits of single draft operation include:

- field production is not dependent on the semi
- simplification of design
- a simple ballast system can be used
- equipment is cheaper to buy and maintain
- system reliability is increased
- crew can be less skilled
- safety is improved

The unit is raised to inspection draught by gravity draining the columns and 'blowing' the pontoon tanks, maximum air pressure is 1.8 BAR (26.5 PSIG). Since tanks can withstand 5 BAR (85 PSIG) the minimum safety factor is 3.2. For safety purposes no personnel are required in the vicinity of the pontoons during ballast evacuation. This approach has been approved by Lloyds.

14.1 Operation in Iceberg Zones

In this case, the MPSS would be equipped with propulsion, Kamewa or Stone Manganese azimuthing thrusters or equal.

It is expected that the design of the installation will permit for planned shutdown of the reservoir, release of risers and moorings and withdrawal to avoid the large icebergs.

Reportedly, smaller icebergs, about ten metres, are problematical. SEL's studies show that the MPSS could be moored, corner to the drift and fenders, made from box-girders, positioned between the bow and the mid-columns, about five metres below the surface.

These would prevent the entry of growlers into the moonpool area. The mooring chains and risers would need protection; chains could be routed down inside the columns and risers routed down over the stern or inboard of the stern column.

It would appear that sufficient clearance for growlers is available on the MPSS, even if fenders are not provided, since the pontoon deck is twenty metres below sea-level and the underside of the main deck is twenty-five metres above sea-level and, provided risers and chains are routed properly, growlers would pass through without damaging the equipment or structure.

14.2 Trim Control

A standard unit, approved by Lloyds and commonly employed for ferries, will be employed for trim control. This comprises draught gauges, programmable logic control, four tanks, valves and an electric pump with standby unit. Draught readings are analysed by the PLC and water transferred from corner to corner by the electrically-driven ballast pump.

Maintenance is confined to chipping, painting and periodic checks for service maintenance on the components of the ballast control system and safety systems.

Maintenance inspection interval is five years, conforming to statutory requirement.

All internal areas of the MPSS are accessible for internal inspection once the tank(s) is emptied. This can be done at operating draught.

15.0 ABANDONMENT AND DISPOSAL

At the end of the field life, the entire installation can easily be removed. The unit will be de-ballasted and raised to transit draught, the chains disconnected, the anchors broken out and the chains stowed on the pontoon decks.

The unit may be refurbished in a ship repair yard using the yard personnel.

16.0 CERTIFICATION

Lloyds fully accept all of the design principles and have conducted a pre-certification assessment of the structure, stability, moorings and ballast piping system They state, "they are satisfied that the design can be approved for the intended service". They have confirmed that they will not require an elevated helideck, propulsion system or internal ventilation for this type of structure. The unit will be certified as a fixed floating structure.

THE FOLLOWING IS AN EXTRACT FROM LLOYDS' RISK ANALYSIS:

"17.0 RISK ANALYSIS

To obtain an impartial technical evaluation of the engineered safety features embodied in the MPSS Seaways commissioned Lloyds Register Department of Safety Technology to conduct a Risk Analysis of the design in qualitative terms.

This comprised the following:

* Identification of hazards common to prospective service applications for the multi-purpose concept of the design; these being ballast system failures, collisions, structural failures and mooring failures.

* Examination of the plans and information describing the design and system arrangements and operting condition of the vessel.

* Cataloguing failures modes, system defences and redundancies.

* Evaluation of effects of failures in terms of floatibilty, stabilty, strucural integrity and station-keeping.

The findings of the analysis have identified that there are no inherent weaknesses in the MPSS design concepts, systems and arrangements with respect to safety feaatures addressable at this stage. The following safety features are highlighted:

17.1 Ballast System

* Reserve buoyancy and tank compartmentalization adopted in the design preclude creation of critical effects on floatability and stability through ballast system failures (based on 4 bay arrangement of pontoon tanks)

* Whilst there is no redundancy in the design of the ballast lines, effects of failures of floatability and stability are not considered to be critical.

- Principles adopted for ballasting operations (free flooding of pontoon tanks, filling of column tanks by fire main, low frequency of need to adjust ballast, (deballasting by compressed air) allow non-complex procedures to be established, hence minimising likelihood of operational errors.

17.2 Collisions

- Reserve buoyancy of columns and further contribution by deck box structure provides substantial survival capability in event of impact damage to any column i.e. critical failure mode would be structural collapse in event of massive structural damage by impact.

- Extensive horizontal and vertical subdivision of columns leads to superior effect of gradual degradation in floatability and stability with increasing damage extent above and below the waterline, rather than rapid loss.

- The disposition and filling of all pontoons and column tanks to a level above the operational draught eliminates potential for flooding through impact for these compartments.

- Exposed corners of columns should be suitably fendered to absorb minor contacts/abrasions.

17.3 Structural Design Concepts

- Compared to many existing semi-submersibles, avoidance of relatively 'delicate' bracing members eliminates associated critical and complex procedures for design (high stress levels in bracings and fatigue sensitivities of details in particular at bracing end connections), construction (alignment) and maintenance (inspection).

  (high stress concentrations and fatigue prone areas of the MPSS are located at the junctions of columns and pontoons, and columns and deck box.)

- Adoption of closed box type construction for all primary structure (pontoons, columns, deck) provides inherent structural redundancy and continuity of strength members without need for sophisticated procedures for fabrication alignment.

17.4 Mooring System

- Proposed station keeping system by means of 12 lines anchor/chain mooring spread is conventional, hence technology is established for this system.

- Proposed submerged arrangements for chain attachments to pontoons with respect to ability to facilitate emergency release are highlighted.

N.B: SAFETY TECHNOLOGY DEPARTMENT is a specialist department of Lloyds Register undertaking safety, risk and reliability studies for marine offshore industry, and is independent of LR's classification and certification services."

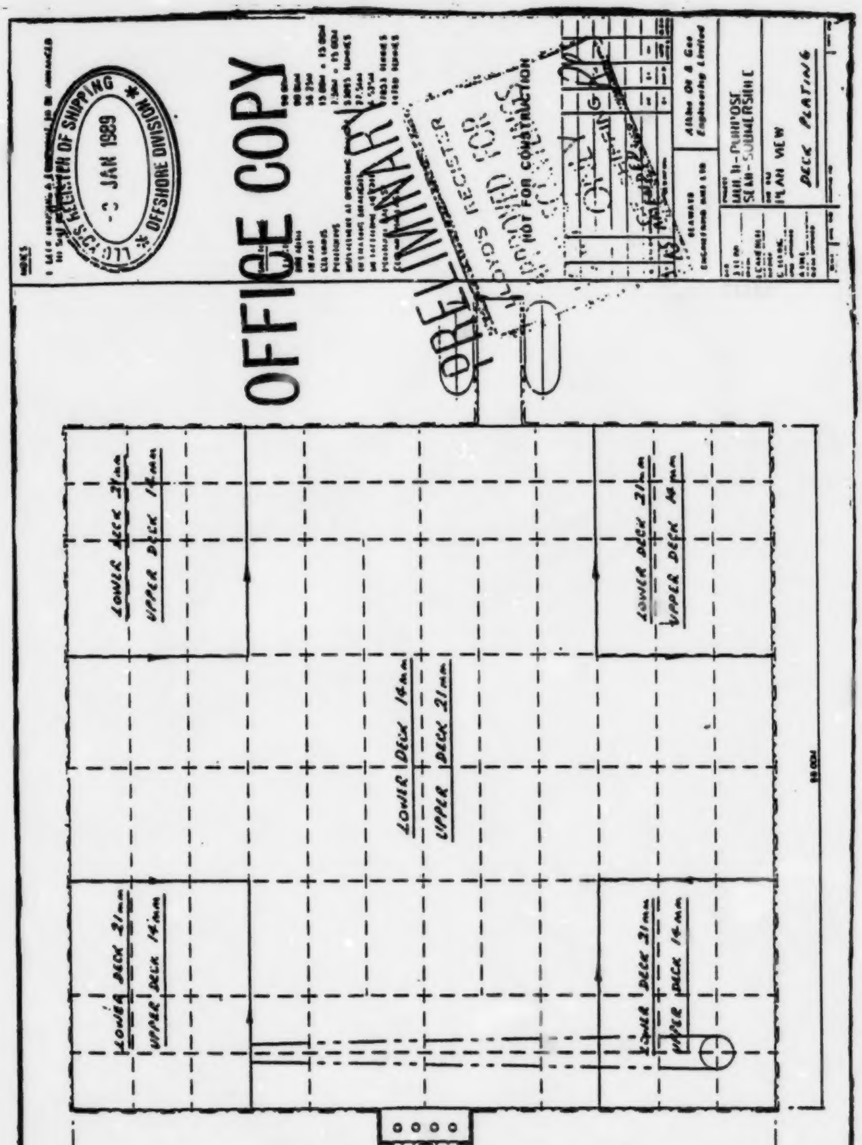
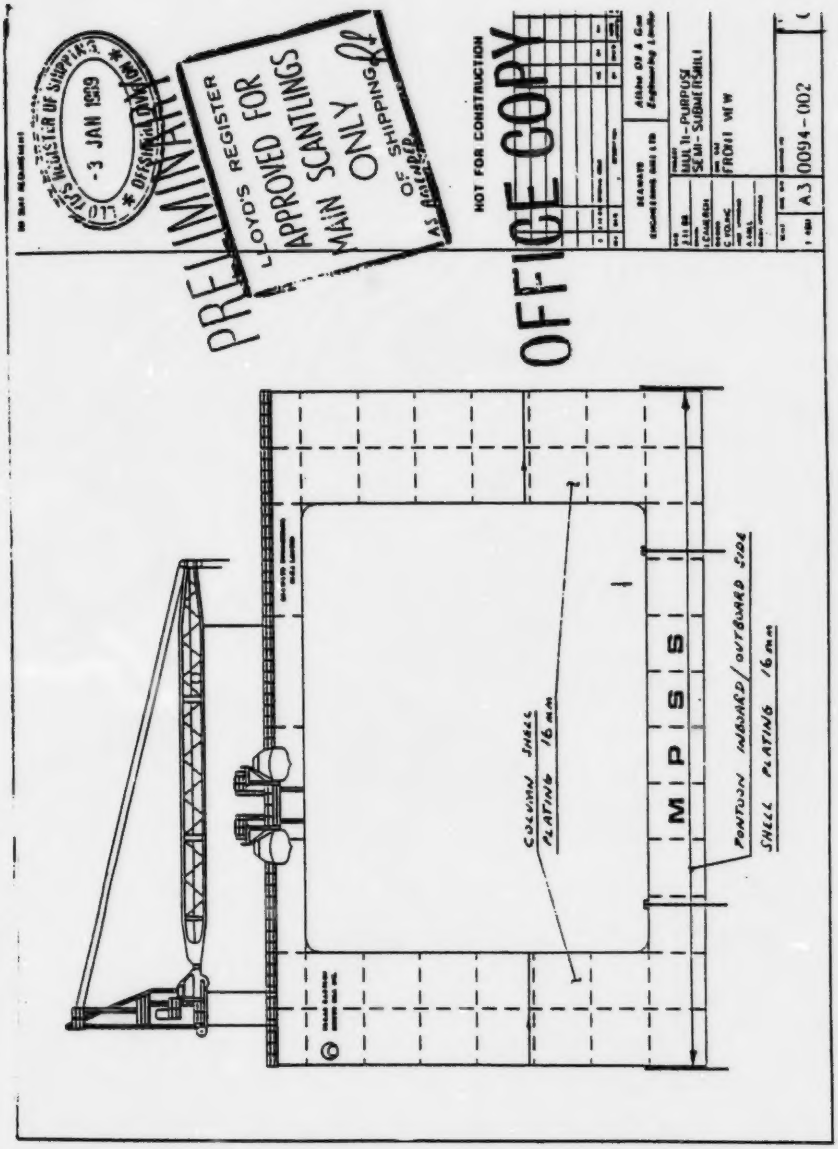

LOWER DECK 21mm
UPPER DECK 14mm
LOWER DECK 14mm
UPPER DECK 21mm
LOWER DECK 21mm
UPPER DECK 14mm
LOWER DECK 21mm
UPPER DECK 14mm
LOWER DECK 21mm
UPPER DECK 14mm
OFFICE COPY
PRELIMINARY
LLOYD'S REGISTER OF SHIPPING
-3 JAN 1989
OFFSHORE DIVISION
LLOYD'S REGISTER
APPROVED FOR
NOT FOR CONSTRUCTION
SEAWAYS ENGINEERING (UK) LTD
Aldme Oil & Gas Engineering Limited
MULTI-PURPOSE SEMI-SUBMERSIBLE
PLAN VIEW
DECK PLATING

FIG2



COLUMN SHELL PLATING 16 mm
PONTOON INBOARD/OUTBOARD SIDE SHELL PLATING 16 mm
M P S S
LLOYD'S REGISTER OF SHIPPING -3 JAN 1989 OFFSHORE DIVISION
PRELIMINARY
LLOYD'S REGISTER OF SHIPPING APPROVED FOR MAIN SCANTLINGS ONLY AS AMENDED
NOT FOR CONSTRUCTION
OFFICE COPY
SEAWAYS ENGINEERING (UK) LTD
Alliance Oil & Gas Engineering Limited
MULTI-PURPOSE SEMI-SUBMERSIBLE
FRONT VIEW
A3
0094-002

F.G 3

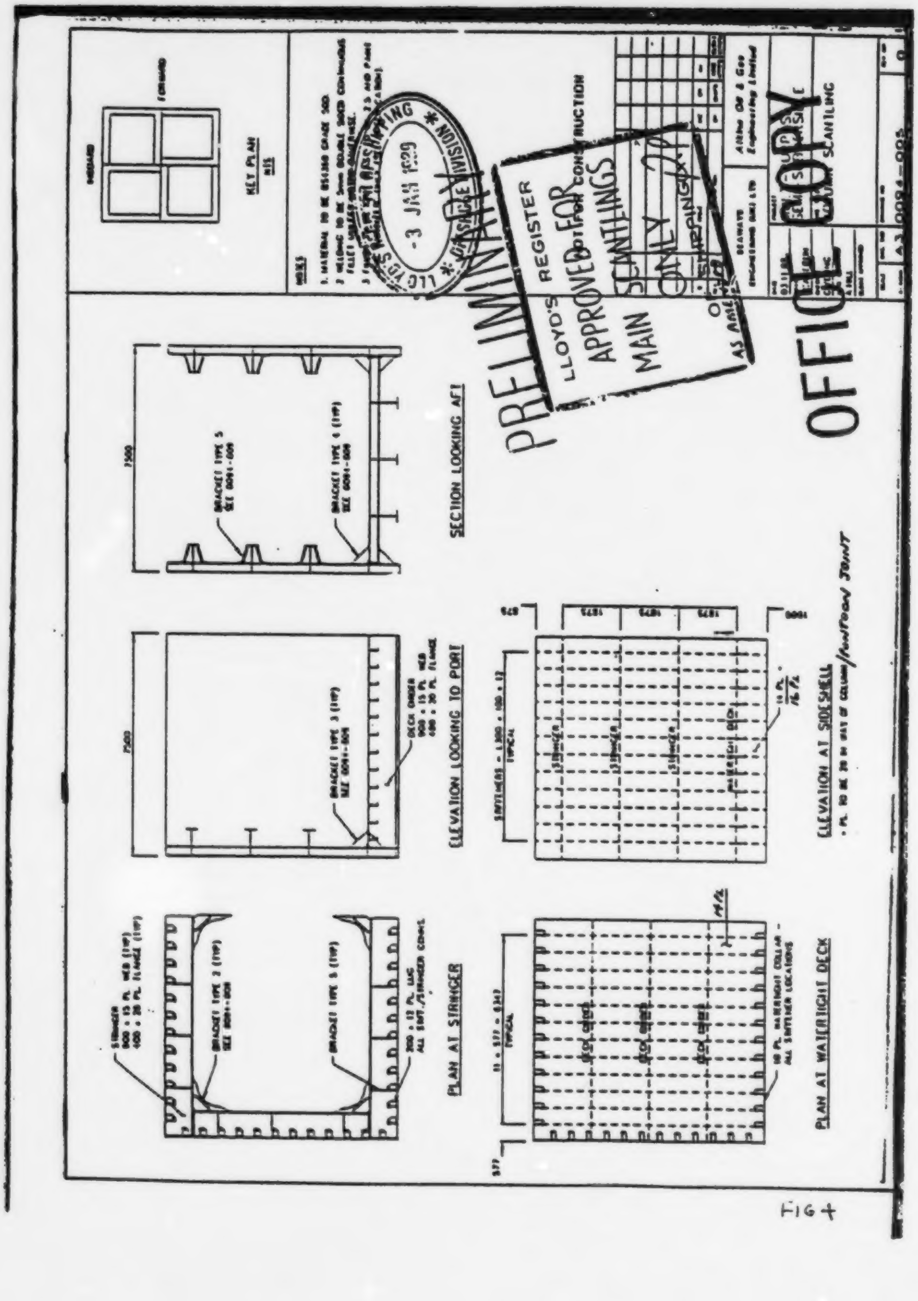

PLAN AT STRINGER
ELEVATION LOOKING TO PORT
SECTION LOOKING AFT
PLAN AT WATERTIGHT DECK
ELEVATION AT SIDESHELL
KEY PLAN
7500
PRELIMINARY
LLOYD'S REGISTER
APPROVED FOR CONSTRUCTION
MAIN SCANTLINGS ONLY
OFFICE COPY
SCANTLING

FIG 4

Wave Period	Hs (m)	Occurrences per year
20.94	2.0	23,047.3
15.44	2.0	442,344.6
12.22	2.0	2,934,115.9
10.12	2.0	4,436,302
8.62	2.0	1,817,741.4
7.52	2.0	1,048,347.6
6.66	2.0	378,460.5
5.98	2.0	82,669.8
Total No. of Waves		11,163,029.1

Wave Occurrences

Figure 5

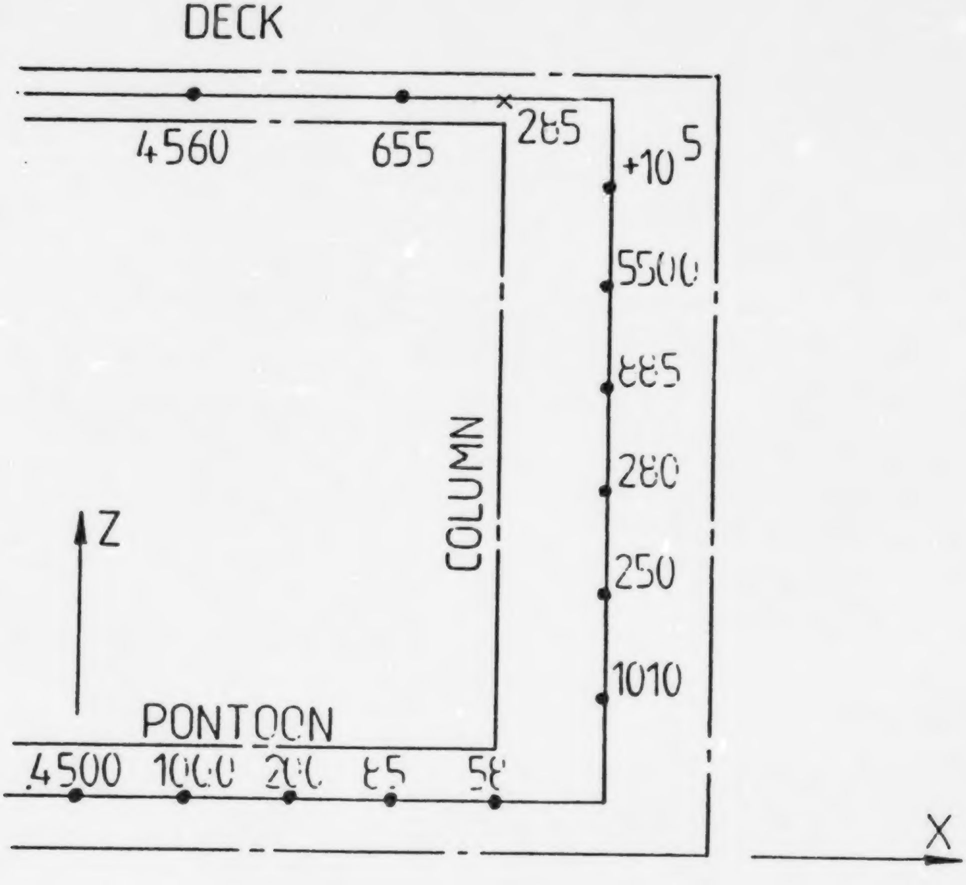
FIGURE 6

MULTI-PURPOSE SEMI-SUBMERSIBLE

FATIGUE LIVES (YEARS)

PERIOD 10·12s WAVE DIRECTION 45deg

F2 CLASSIFICATION


DECK
4560
655
285
+10^5
5500
885
280
250
1010
COLUMN
Z
PONTOON
4500
1000
200
85
58
X

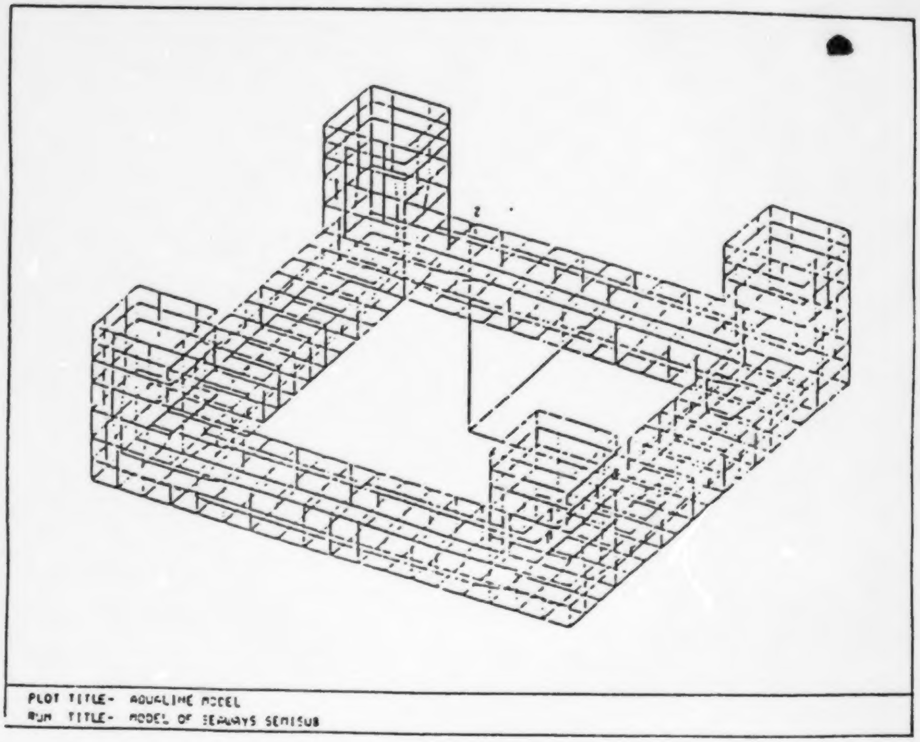
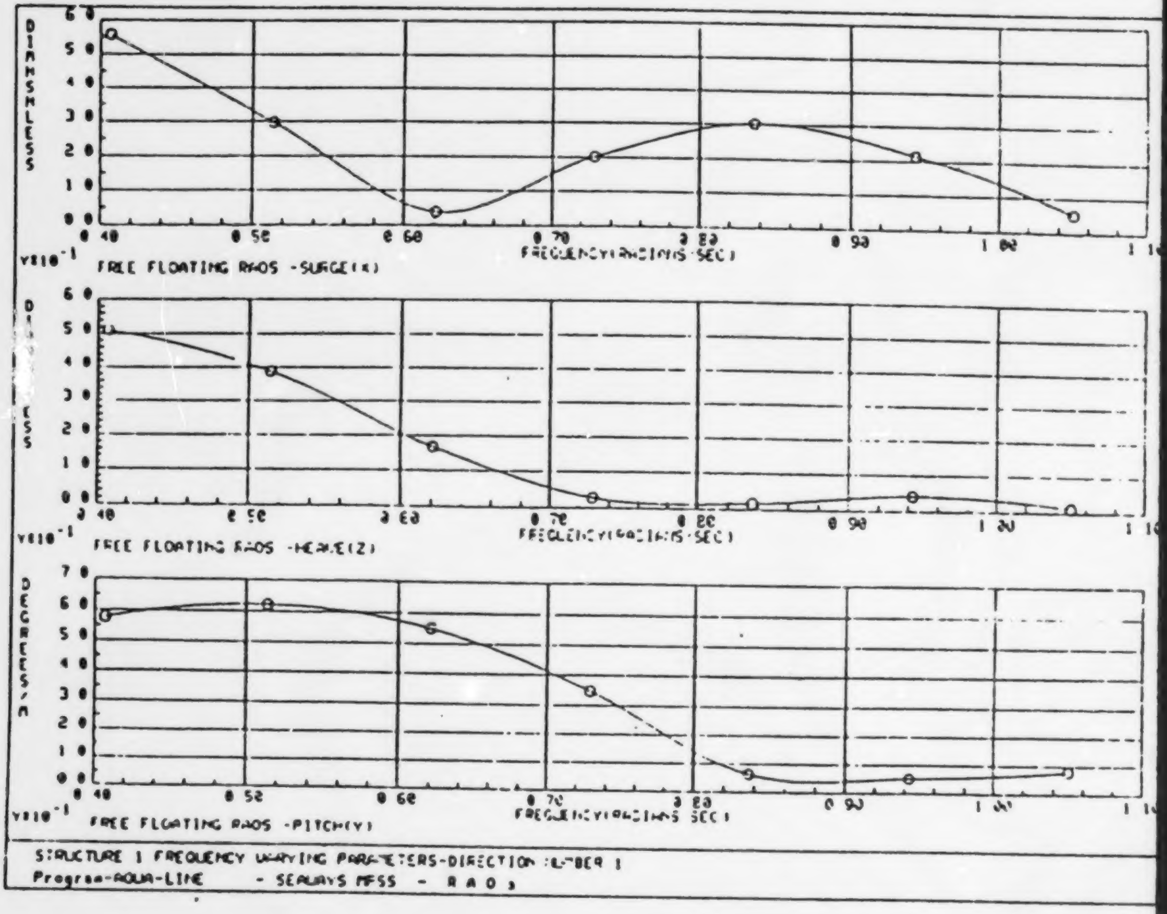

z
PLOT TITLE- AQUALINE MODEL
RUN TITLE- MODEL OF SEAWAYS SEMISUB

FIGURE 7

FIGURE 8


DIMNSNLESS
6 0
5 0
4 0
3 0
2 0
1 0
0 0
0 40
0 50
0 60
0 70
0 80
0 90
1 00
FREQUENCY(RADIANS/SEC)
Y*10^-1
FREE FLOATING RAOS -SURGE(X)
DIMNSNLESS
6 0
5 0
4 0
3 0
2 0
1 0
0 0
0 40
0 50
0 60
0 70
0 80
0 90
1 00
FREQUENCY(RADIANS/SEC)
Y*10^-1
FREE FLOATING RAOS -HEAVE(Z)
DEGREES/M
7 0
6 0
5 0
4 0
3 0
2 0
1 0
0 0
0 40
0 50
0 60
0 70
0 80
0 90
1 00
FREQUENCY(RADIANS/SEC)
Y*10^-1
FREE FLOATING RAOS -PITCH(Y)
STRUCTURE 1 FREQUENCY VARYING PARAMETERS-DIRECTION NUMBER 1
Program-AQUA-LINE - SEAWAYS MESS - R A O s

Degree of Freedom	Natural Period (secs)
Heave	24.0
Roll	42.2
Pitch	42.2

Natural Periods of Oscillation of Vessel

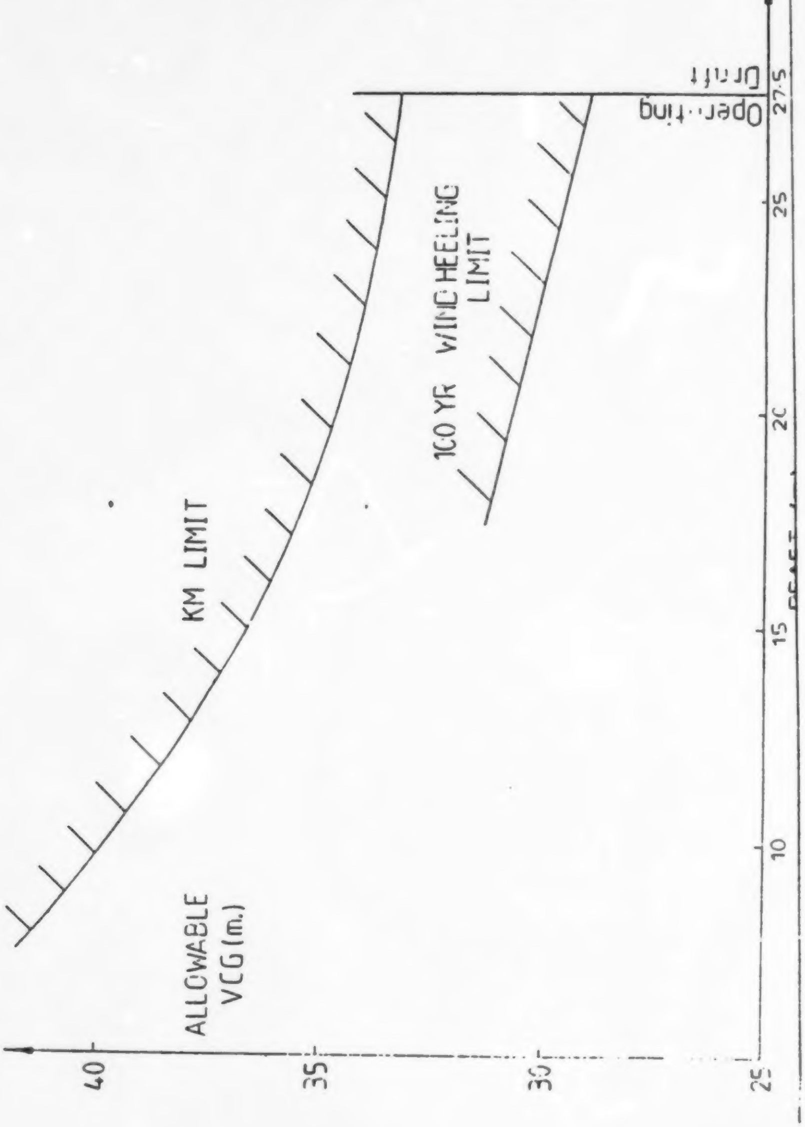
Figure 9

Draught	t	27.5m
Displaced volume		$51750 m^3$
Cut water plane area	A	$900 m^2$
Centre of buoyancy above keel	KB	8.533m
Displacement		53095 tonnes
Mass	M	52495 tonnes
Fluid density		1026 tonnes/m^3
Centre of gravity (above keel)	KG	26.79m
Water plane inertia	Ixx	1.283 x 10 m
Water plane inertia	Iyy	1.283 x 10 m
Radius of gyration	Kxx	39.38m
Radius of gyration	Kyy	39.38m
Radius of gyration	Kzz	44.47m
Metacentric height	GM	6.525m

Vessel Properties at Hydrodynamic Analysis Position

Figure 10

FIGURE 11 ALLOWABLE VCG LIMITS



Draught (m)	Displaced Volume (m^3)	KB (m)	KMT/KML (m)
6.8	30645	3.395	146.576
8.0	34200	3.803	41.303
10.0	36000	4.063	39.687
12.0	37800	4.393	38.321
14.0	39600	4.785	37.171
16.0	41400	5.229	36.207
18.0	43200	5.719	35.406
20.0	45000	6.250	34.750
22.0	46800	6.817	34.221
24.0	48600	7.417	33.806
26.0	50400	8.045	33.491
27.5	51750	8.532	33.315

Hydrostatic Properties of Vessel at Varying Draught

Figure 12

Draught (m)	KG MAX (m)
18.0	31.20
27.5	28.28

Maximum Vertical Centre of Gravity Position as Limited by Wind Heeling

Figure 13

Displacement	53095 tonnes
Roll angle	6.74 degrees
Pitch angle	6.69 degrees
Minimum downflooding distance	16.94 metres

Description of Vessel in Damaged Equilibrium Position

Figure 14

	Wind Heeling Moment (KNm)	
	Initial Draught (m)	
Heel Angle (degrees)	18.0m	27.5m
0.0	435,000	360,000
10.0	645,000	512,400
20.0	795,800	642,000
25.0	N/A	763,100
30.0	1,068.000	

Wind Heeling Moment Variation with Heel Angle

Figure 15

Draught (m)	Downflooding Angle (degrees)
18.0	28.61
27.5	24.13

Downflooding Angle for Various Draughts

Figure 16

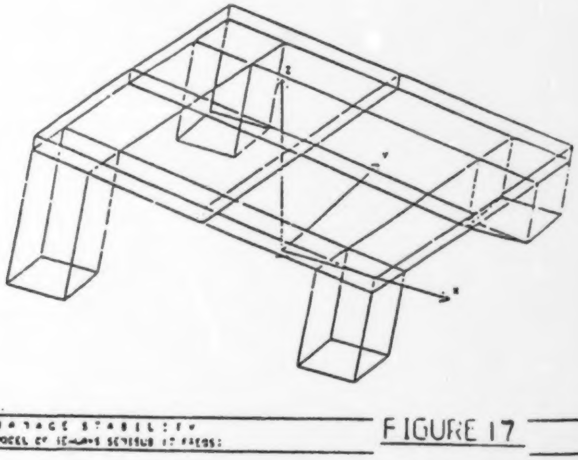
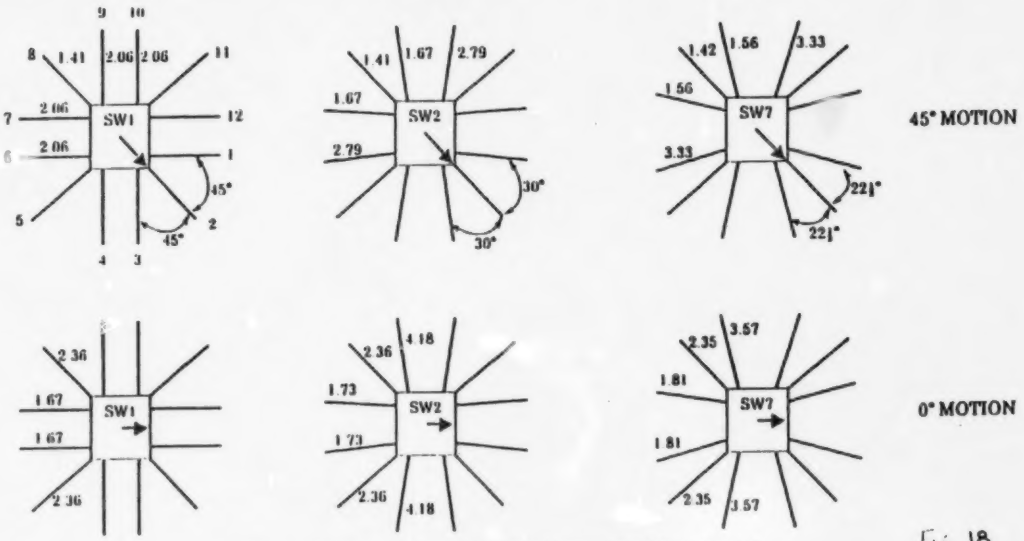

PLOT TITLE- DAMAGE STABILITY
RUN TITLE- MODEL OF [illegible]

FIGURE 17

Multi-purpose semi-submersible anchor line factors of safety
(from steady force and maximum wave motion)



9
10
8
1.41
2.06
2.06
11
7
2.06
SW1
12
6
2.06
1
45°
5
45°
2
4
3
1.41
1.67
2.79
1.67
SW2
2.79
30°
30°
1.42
1.56
3.33
1.56
SW7
3.33
22½°
22½°
45° MOTION
2.36
1.67
SW1
1.67
2.36
2.36
4.18
1.73
SW2
1.73
2.36
4.18
2.35
3.57
1.81
SW7
1.81
2.35
3.57
0° MOTION

Fig. 1
ORIGINAL PATTERN

Fig. 2
REVISED PATTERN
30° ALL ROUND

Fig. 3
REVISED PATTERN
22½°/45°

Same pre-tension all round (150T in-line or 1258kN horizontal

Fig 18

Water Depth	150 m
Depth of Attachment Point	20.0 m
Length of Chain	1350 m
Diameter	92 mm
Mass per unit length (in air)	190.40 kg/m
Minimum breaking load	8520 kN
Effective Young's Modulus	5.6 x 10 N/m^2
Pre-tension	150 tonnes

Mooring Line Properties

Figure 18

Sources: Ramnas Anchor Chain Catalogue, NMD regulations on Positioning Systems for Mobile Offshore Units (Ref.2).

Waves	Significant Wave Height	16.5m
	Zero Crossing Period	13 - 15 secs
	Spectral Shape	Pierson-Moskowitz
Current	Tidal Current	0.5 m/s
	Wind Induced Current	0.8 m/s
Wind	Maximum Mean Hourly Wind Speed	38 m/s

Extreme Environmental Conditions for Mooring Analysis

Figure 19

Load Component	Weather Heading		
	0°	22.5°	45.0°
Wind	2625 KN	3414 KN	3581 KN
Current	2587 KN	2953 KN	3689 KN
Wave Drift	405 KN	324 KN	245 KN
TOTAL	5617 KN	6691 KN	7515 KN

Extreme Environmental Loads

Figure 20

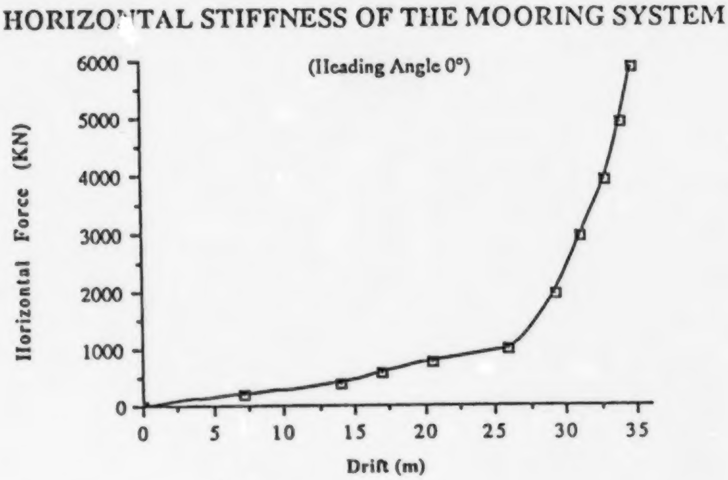
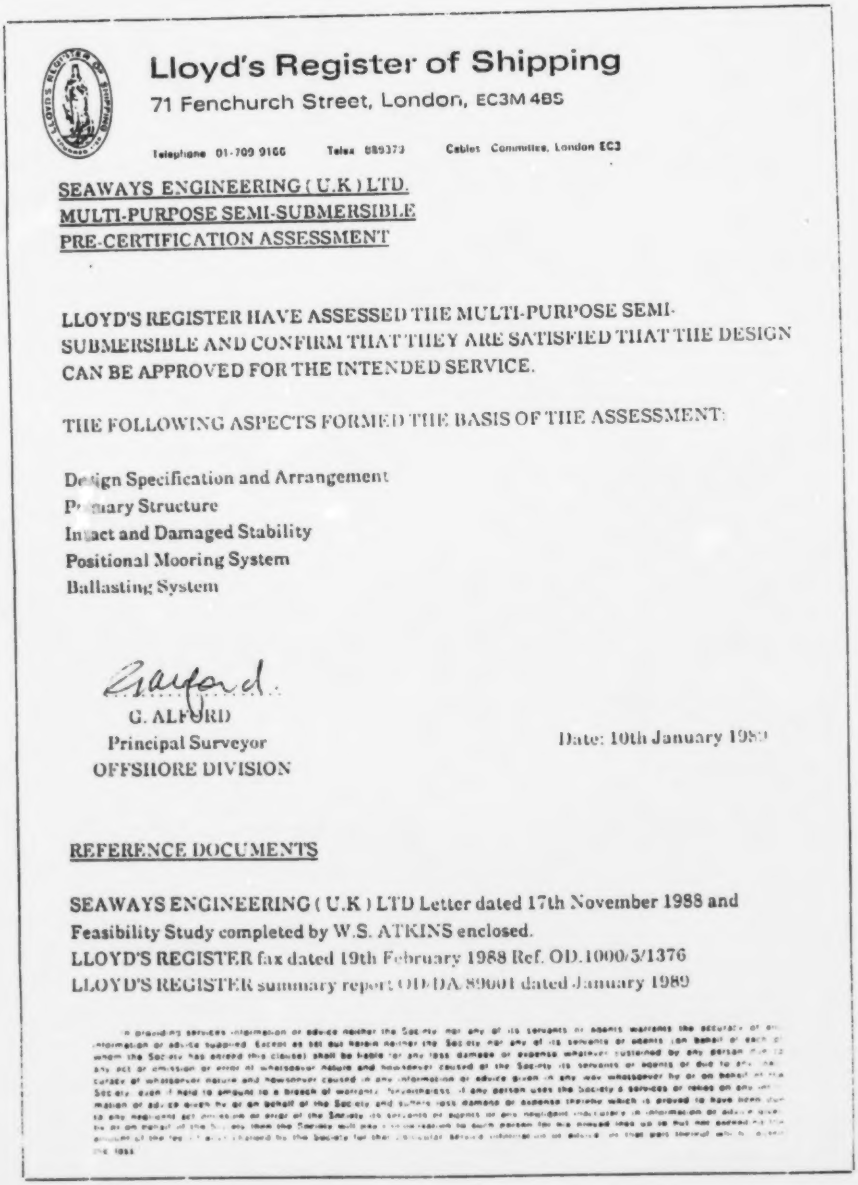


FIG. 22

SURVIVAL

STRAN CASE No.	WAVE NO	WAVE HEADING	WAVE HEIGHT	WAVE PERIOD	CREST POSITION	FORCE/ MOMENT	FORCE ASSOC.	FORCE RATIO
1	1	180.00	15.00	9.40	-75.00	2c	-1.156E-04	-1.00
	1	180.00	15.00	9.40	-75.00	2d	-1.156E-04	-1.00
	1	180.00	15.00	9.40	-75.00	2f	-2.312E-04	-1.00
2	2	180.00	23.30	12.10	25.00	2f	+4.434E-03	-1.00
	2	180.00	23.30	12.10	25.00	2d	+2.217E-03	-1.00
	2	180.00	23.30	12.10	25.00	2c	+2.217E-03	-1.00
3	3	180.00	27.30	13.30	38.00	6a	-1.404E-06	-1.00
4	4	180.00	27.30	13.30	-60.00	1c	+6.048E-03	-1.00
5	5	180.00	33.60	15.50	114.00	3a	-1.346E-04	-1.00
6	6	180.00	33.60	15.50	76.00	1c	-8.045E-03	-1.00
7	7	180.00	33.60	15.50	-76.00	3a	-2.849E-04	-1.00
8	8	180.00	36.30	17.50	94.00	4b	+4.044E-05	-1.00
9	9	180.00	36.30	17.50	-47.00	6a	-2.043E-06	-1.00
	9	180.00	36.30	17.50	-47.00	4b	-6.282E-05	-1.00
10	10	202.50	10.00	7.60	50.00	4c	-1.048E-05	-1.00
11	11	202.50	10.00	7.60	0.00	4c	+1.301E-05	-1.00
12	12	202.50	36.30	17.50	133.00	2a	+2.290E-03	-1.00
13	13	202.50	36.30	17.50	47.00	2b	-3.079E-03	-1.00
14	14	202.50	36.30	17.50	0.00	2e	-5.561E-03	-1.00
15	15	202.50	36.30	17.50	-47.00	2a	-3.017E-03	-1.00
16	16	202.50	36.30	17.50	-135.00	2b	+2.309E-03	-1.00
17	17	202.50	36.30	17.50	-225.00	2e	+4.117E-03	-1.00
18	18	225.00	10.00	7.60	-50.00	5a	+1.148E-05	-1.00
19	19	225.00	15.00	9.40	-75.00	5b	-1.327E-05	-1.00
20	20	225.00	20.00	10.30	-100.00	1a	-4.101E-03	-1.00
21	21	225.00	23.30	12.10	0.00	5a	-2.017E-05	-1.00
	21	225.00	23.30	12.10	0.00	5b	-2.533E-05	-1.00
22	22	225.00	33.60	15.50	114.00	3b	+7.211E-03	-1.00
23	23	225.00	33.60	15.50	38.00	1a	-5.324E-03	-1.00
	23	225.00	33.60	15.50	38.00	1b	-5.044E-03	-1.00
24	24	225.00	36.30	17.50	78.33	3c	-4.682E-04	-1.01
	24	225.00	36.30	17.50	78.33	6b	-1.458E-06	-1.02
	24	225.00	36.30	17.50	78.33	4a	-2.179E-05	-.97
25	25	225.00	36.30	17.50	-94.00	3b	-9.520E-03	-1.00
	25	225.00	36.30	17.50	-94.00	6b	-1.342E-06	-1.00
	25	225.00	36.30	17.50	-94.00	3c	-5.701E-04	-1.00
	25	225.00	36.30	17.50	-94.00	4a	-1.331E-05	-1.00
26	26	225.00	36.30	17.50	-141.00	1b	[illegible]	-1.00
27	27	-1.00	-1.00	-1.00	-1.00	3c	-5.101E-04	-1.00

FIG. 23



Lloyd's Register of Shipping
71 Fenchurch Street, London, EC3M 4BS

Telephone 01-709 9166 Telex 889373 Cables Committee, London EC3

SEAWAYS ENGINEERING (U.K) LTD.
MULTI-PURPOSE SEMI-SUBMERSIBLE
PRE-CERTIFICATION ASSESSMENT

LLOYD'S REGISTER HAVE ASSESSED THE MULTI-PURPOSE SEMI-SUBMERSIBLE AND CONFIRM THAT THEY ARE SATISFIED THAT THE DESIGN CAN BE APPROVED FOR THE INTENDED SERVICE.

THE FOLLOWING ASPECTS FORMED THE BASIS OF THE ASSESSMENT:

Design Specification and Arrangement
Primary Structure
Intact and Damaged Stability
Positional Mooring System
Ballasting System

GAlford.
G. ALFORD
Principal Surveyor
OFFSHORE DIVISION

Date: 10th January 1989

REFERENCE DOCUMENTS

SEAWAYS ENGINEERING (U.K) LTD Letter dated 17th November 1988 and Feasibility Study completed by W.S. ATKINS enclosed.
LLOYD'S REGISTER fax dated 19th February 1988 Ref. OD.1000/5/1376
LLOYD'S REGISTER summary report OD/DA 89001 dated January 1989

SPEAKER : **LARS FOYEN**

COMPANY : **DET NORSKE VERITAS (CANADA) LTD.**

LOCATION : **CALGARY, ALBERTA, CANADA**

TOPIC : **A MODERN CERTIFICATION SCHEME**

BIOGRAPHY: Mr. Foyen graduated from Haviot-Watt University in Edinburgh, Scotland in Mechanical Engineering in 1967. Following Det norske Veritas' postgraduate scheme, he worked with Det norske Veritas in the U.K. for four years, then six years in the Research Division up to 1980, when he moved to Aberdeen and became District Manager, Scotland. He has worked extensively with offshore certification and ship classification. Since April 1, 1989, he has taken over as president of Det norske Veritas (Canada) Ltd.

1. INTRODUCTION

The building, installation and operation of offshore installations represent very large industrial projects. The potential consequences of problems, damage, delays etc are consequently also large in terms of loss of life, damage to the environment and financial loss. That is, large enough for politicians and National Authorities to take an interest. National Authorities have tended to impose independant third party Certification requirements on such projects. Though the size of the third party certification typically amounts to less than one percent of the overall project cost, it is still significant in size. Due to the usually sensitive position of the Certification tasks in the schedule of the main project and for the parts being delivered to the project, timely delivery of decicions, reports and certificates from the Certifying Authority is important to the smooth running of the main project.

The following is a discussion of some of the fundamentals of the Certification process together with methods and practical aspects that should be considered in order to achieve efficient handling.

2. SOME FUNDAMENTAL ASPECTS OF THE CERTIFICATION PROCESS

The primary purpose of third party Certification is to obtain an independent assessment of all the important aspects of the project, thus increasing the confidence of other interested parties that correct design, engineering, installation, commissioning and operation procedures are applied in the project.

Decisions regarding the degree of involvement are commonly geared to the criticality of what is being considered. Referring to Fig.1, the involvment of the Certifying Authority can be thought of as consisting of the following types of activities:

- design review
- survey during manufacture
- survey during installation
- document review

For critical parts, the Certifying Authority involvement would be comprised of all four activities. Fig. 1 shows how this is generally reduced for less critical, i.e. Categories II and III equipment. The extent and detail of involvement under each category is of course also an important variable, and may be influenced by e.g. the quality of the relevant QA and Quality Control schemes in force, the degree of novelty, or the degrees of technical and organisational complexities involved.

For equipment, a grouping based on criticality rating is usually assigned based on the hazardous nature of the contents or fluids handled, the energy stored, the power rating and speed of rotating machinery, the capacity of lifting gear, etc.
Examples of such groupings can be found in most pressure vessel codes, in the Norwegian Petroleum Directorate's (NPD) Regulations for Drilling Equipment, and in Det norske Veritas' Rules for Mobile Offshore Units for the Drilling Plant Class Notation.

The criticality grouping of components has traditionally been assessed on the bases of knowledge of the component specifications. This can obviously be further refined if the full function and physical location of the component on the installation are known. Factors like proximity of the installed component to personnel, essential equipment and structures can then be included in the evaluation of criticality.

In Certification, criticality also forms the basis for deciding the type of documentation required. The concept of Positive Reporting which implies including a detailed description of test values, findings and results in certificates and reports inspires more confidence than just generalized statements of conformity. This is of course in conflict with the desire to keep the volume of documentation down. A further discussion on ways of optimising these conflicting interests are considered under the section on cost implications below.

Fig 2 is an illustration of how confidence level may be considered as a function of the type of Material Certificate. References to the various types of Material Certificates are found e.g. in the German Standard DIN 50 049. It should be noted that the confidence levels indicated are purely a subjective judgement, as statistical support for these values is hard to find.

The Design Review is perhaps the most important task, and this is where an experienced Certifying Authority may contribute most to a project. Offshore Projects tend to be prototypes in many respects, with many people, manufacturers and suppliers working together for the first time. In this phase the Certifying Authority has a mission to ensure that the efforts and solutions are consistent with the minimum design premises, and to help in identifying the faults before they are buildt into the installation. By drawing on past experience, the experienced CA can also provide a feedback loop from past similar problems and acceptable solutions. Once into the manufacturing and installation phases, the main aim is to survey important aspects, and take non-conformances up with the Operator. Dealing with non-conformances may involve solutions ranging from complete replacement, to repairs or assessment from first principles in order to assess 'Fitness for Purpose' rather than strict adherence to generalised Standards or Specifications.

3. TYPES OF STATUTORY REQUIREMENTS

National Certification Schemes Perhaps the most important influence on any Certification Scheme are the Rules, Regulations and Guidance established by the relevant National Authority. This forms minimum requirements for an offshore installation and usually includes requirements to a third party involvement for important aspects. The third party involvement may take different forms. A brief outline of the Canadian, Norwegian and U.K. schemes are given below.

CANADA

Canada is in the process of adopting a scheme which is similar in nature to the U.K. scheme. The Operator has to select a Certifying Authority from a list of recognised Certifying Authorities. It appears that fewer agencies will be used for the different aspects of Installations than in the U.K. scheme. It is thought that this should improve on a potential problem area. A difference from the U.K. scheme is that the Authorities are appearently making the Certifying Authority scope subject to approval. The approved scope will then be used as reference for an Audit on the Certification Project. Periodic reporting to the Authorities from the Certifying Authority is also expected to be a requirement.

NORWAY

The Norwegian Offshore Regulations represent an example of a scheme were emphasis is placed on a Quality Assurance programme for the building project and for the In-Service phase. The Operator submits the programme for approval to the Authorities. Once approved, the Operator is responsible for running the project according to the approved QA programme, and the project is subject to Audits from the Authorities. The QA programme must include the procedures for how the project will satisfy the relevant Regulations, which provide detailed requirements on all relevant aspects. The Regulations also specify instances when a third party involvement is required e.g. for Design Review or Inspection. This scheme does not use third parties or Certifying Authorities designated by the National Authority. However, organisations like Det norske Veritas or its subsidiaries tend to be used extensively by the Operators and manufacturers under this scheme as the requirements for technical skills and resources are similar to the schemes based on dedicated Certifying Authorities. We have also been used by the Authorities to assist with the Audit function for which they are responsible.

UNITED KINGDOM

The Certification Scheme in the United Kingdom differs from the Norwegian scheme in that it specifies that Operators have to use one of the six appointed Certifying Authorities to review and survey all important stages and aspects of the Offshore Installation. The emphasis in this scheme is more on the Certifying Authority involvement right through the newbuilding and In-Service phases of the Installation, while there is as yet no formal requirement to implement a QA scheme for the Project. Individual suppliers are, however, encouraged to implement and use recognised QA programmes. Quality Assurance programmes have also been used for some of the more successful projects. Later we will consider how this may be used to modify the third party certification scope. The overall responsible Authority is the Department of Energy. They use several Agencies to cover the complete installation. In addition to the Certifying Authority, the Department of Trade looks after lifesaving appliances, gas detection and active fire fighting measures, while the Pipeline Inspectorate of Department of Energy looks after pipelines and risers up to the first valve on the installation above the water level.

4. TOOLS AND PROCEDURES

To satisfy the job requirements as a Certifying Authority under a National Scheme, or for Third Party Verification for An individual installation, the items considered in the following have been found to be of importance.

4.1 QUALITY ASSURANCE

The principles of Quality Assurance are well established, and most National Schemes adopt the latest ISO 9000 standard for the National Quality Assurance versions.

Formal Quality Assurance Schemes are increasingly being adopted by Manufacturers, Fabricators and by Projects. It may be of interest that an organisation like Det norske Veritas compares to a Service type industry, and a formal QA scheme has been implemented for internal use.

The principles laid down in the Quality Assurance standards are fairly obvious, and any serious operation should be expected to adopt such standards. It is unfortunate, and perhaps worrying to see the number of firms which after making a big effort to produce a QA manual leave it to gather dust on a shelf somewhere while the operation carries on in more or less open disregard of the good principles in the QA-manual.

As a Certifying Authority we regularly come across the question of the effect that a formal QA-scheme will have on the CA involvment. Normally our involvement is with the critical aspects, and an involvment is still required. Commonly, in such cases a Component Certificate is required or the National Regulations may stipulate a third party involvement. Under a Certification scheme, the QA scheme may thus be regarded as an additional measure. Fig. 3 illustrates how the CA involvment may be modified depending on the scope and correct implementation of a formal QA scheme. We consider it important to retain a certain minimum involvment in order to be able to detect deviations from the agreed scheme.

4.2 PROJECT MANAGEMENT ORGANISATION

From the design review and knowledge of where items are being produced, the CA needs to inform the survey stations and surveyors local to the manufacturers regarding the project specific information, the relevant survey scopes, etc. The CA must also receive reports, Release Notes and subsequent Certificates as well as lists of any Non-conformances back from the surveyors. Construction projects of this size tend to be International, and it is important to keep track of any further subcontracting from the original Purchase Order. In Det norske Veritas we have found that a Project organisation of the Certification task is important in order to handle the information requirements and the project specific procedures and requiremets, and also to make an easy contact point for the operator. A project manager is appointed, a Project Information Manual (PIM) is established for the specific certification project in line with the internal DnV QA requirements for PIM's. Making use of efficient communication facilities and Project Management tools the Certifying Authority can then be in a position to deliver conclusions and correct paperwork on time.

4.3 DESIGN REVIEW TOOLS

The design review of a newbuilding project involves the review of specifications, drawings and calculations, and normally an independent check by performing independent analyses of the more critical aspects of the primary structure. The number of specifications, drawings and calculations runs into the tens of thousands for large projects. Efficient handling and capacity to achieve a reasonable response time is obviously important.

The design review requires a fundamental understanding of the components and processes involved, as well as access to and handling the software where a double check is regarded as necessary. Relevant calculations are commonly requested as part of a submission. The CA should, however have the capability to carry out a design check from first principles, and have the necessary tools and capabilities for this. To be effective in this area also means keeping up with technological developments. Apart from the design reviews, this is achieved through a number of activities like research and development, taking an active part in the development of Rules, standards and our own Classification Rules, and in the development of software for a wide range of applications.

For structural and mechanical components, calculation capabilities are required for evaluating normal and accidental loads and converting this into a form that can be used to assess all potentially relevant failure modes, i.e. rupture, yield, brittle fracture, fatigue, stability, displacement and creep.

Hydrodynamics and stabiltiy considerations are important aspects of most installations.

For the process parts of the installation, design review requires handling of blow-down capacities, temperature effects from pressure drops in gas systems, gas dispersion rates, hazardous area classification, heat loading from flare systems, assessing fire barriers, blast walls etc.
Risk Analyses (RA) has been part of the Statutory requirements from the early days of the North Sea development in Norway, and somewhat later also in Denmark. As offshore installations tend to be unique designs, the Risk Analyses represents an expedient method of identifying problems at an early stage of a project. NPD (1986) Regulations for example specify an annual probability level of 10-4 below which loads or events are considered abnormal and can be disregarded. It is therefore necessary to exstablish the risk level for such rare events as blow-outs, earthquakes and, of special relevance to the Canadian East Coast, iceberg colliisions. This requires risk analyses which may be based on historic information such as fire or explosion data, or environmental data coupled with analyses models such as in the case of icebergs.

NPD also specifies that safety evaluations should be carried out at an early stage of the project to ensure that hte selected concept is acceptable. The purpose of safety evaluations is to verify that the probability of losses in human life, environmental pollution and extensive material damage is sufficiently small. An example of the scope and approach to such analyses is given in Fig.6 (Toerhaug et al, 1984). These analyses can rely on historic data and such approches as fault and event trees. In many cases the approach chosen for the risk analysis, the assumptions made, the level of detail, the hazards addressed and the data used involve subjective judgment. Quantitative results can therefore vary substantially for similar problems, as observed by Goldschmidt et al, 1987 in a comparison of 14 risk assessments of installations in the Danish sector. It is therefore important to have such analyses carried out or verified by and interpreted by engineers with experience in risk analyses and familiarity with the problems likely to be encountered. Despite these limitations the above authors have observed that risk analyses carried out at the conceptual stages have had a positive influence on the design and that numerous recommendations were made and implemented especially when new technology is involved.

We therefore believe that risk and probabilistic analyses are among the important tools for certification of installation concepts and criteria selection. DnV has built condiderable experience and developed effective tools in this area.

4.3.3 MANAGEMENT OF SAFETY REQUIREMENTS TO INSTALLATION

Safety requirements arise from a number of sources:

National Regulations
Standards called up by the Regulations
Results from CA design review
Results from Risk Analyses

Keeping track of the safety related design aspects of an installation becomes considerable. With the construction and installation phases stretching over 2-3 years and the subsequent production phase lasting for 15-20 years or more, it is evidently easy to loose track of the reasoning behind the variers design aspects. This is a common source of Non-Conformances, particularly in the in-service phase. In the past we have advocated the development of a Design, Fabrication and Installation (DFI) document or manual for summarising such information for use primarily in the In-Service phase. With the advent of the Personal Computer (PC) we would now recommend the use of a database application for the management of this information. A PC-based data-base tailored to the project specific name conventions for logging of requirements applicable to the individual system, area or part. The application was originally developed for an Operator's own use in the management of safety aspects and requirements to installations. Fig. 3 shows the basic elements handled by such a program.

5. COST IMPLICATIONS OF CERTIFICATION

The direct costs to the third parties may be of the order of 0.5 to 1.0 percent of the newbuilding costs of a project. Even though this compares favourably with the costs of e.g. financial and legal services for a project, it is of course still significant enough for most Operators to use a normal bid process for the Certification contract.

The secondary costs, i.e. the costs incurred by the Operator and by subcontractors and manufacturers in handling the certification process are more significant. Concerns have been voiced increasingly over the shear volume of documentation involved, refer e.g. to ref [5]. Conferences have been held dealing with the documentation epidemic. For recent installations in the North Sea the design, fabrication and operation related documentation weighs in at 30-50 tonnes of paper, and is a considerable cost element to a project. Overall consideration of availabilty and operability including the operational and production aspects may well be good reasons why Operators are often exceeding the minimum requirements established primarily from safety considerations. This does not explain the large difference found when comparing fairly similar projects using the simpler organisations established in shipbuilding. V. von Hoffman at OTC 1988, Ref [6], compared the costs of two projects, one a floating production vessel (FPV) subject to the project organisation and procedures as an offshore installation, the other a mobile drilling unit using the more traditional shipbuilding organistation and practices. He concluded that apart from the greater size, weight and complexity, cost increases were due to:

Higher quality requirements
Lerning costs, first FPV project
Certain project administration methods

He concluded that a cost saving of 20 percent, equally divided between the three factors is feasible. The latter factor would thus indicate a potential saving of 5-6 percent using project administration more in line with traditional shipbuilding project management.

To facilitate exploring this potential, we have recently developed Classification Rules for fixed offshore structures.

Uncertainty with respect to what documentation is required, and the tendency in this case to cover all eventualities is another source of excessive documentation. This is an area where we put in a considerable effort to develop publications to provide specific and acceptable procedures.

An example of this is the section on drilling equipment in our Rules for Classification of Mobile Offshore Units. Requirements to cover the U.K. and Norwegian certification schemes are covered as additions to a set of basic requirements. The Rules also covers minimum documentation and survey requirements, and reduces considerably the effort required to decide correct certification scope.

As a further contribution to rationalising certification, we have developed a Type Approval scheme for the benefit of equipment manufacturers. This is a formal scheme where a product or range of products are submitted for approval according to a reckognised standard or specification. On passing this review equipment is entered into lists of Type Approved equipment. The design code and the design conditions used for the review are also listed. depending on the particular application, a component certificate may be required in addition to this listing. The component certificate covers the third party involvement in the manufacturing and testing phases. Several options are available based on direct surveys or degrees of auditing an established Quality Assurance scheme.

Are there any measures which can be applied to deal with the incredible volume of documentation resulting from an offshore project? It has been suggested that for the fabrication documentation it may be acceptible to discard this once it has been proven to be in accordance with the specifications. The specifications would then be the main reference for inspection and repair purposes later on in the life of the installation. In the past, difficulty has been experienced by a number of past in transferring the documentation to the in-service organisation and providing adequate retrieval systems. Relying on the specifications only for repair or modification procedures has thus been practiced to some extent. A more widespread adoption and formalisation of this procedure could be feasible. This of course does not eliminate documentation requirements. The solution for the documentation that is required would be to use the latest in information technology to cope with volumes, and design the information logging and retrieval system so that standardisation is enforced from an early stage of the project.

In the area of inspection and NDE, development work has taken place using probabalistic methods to decide inspection scopes, inspection frequencies and methods to ensure adequate reliability. Madsen et al in [1] describes a stochastic model for fatigue crack growth and demonstrates calculation of failure probabilities and how updating can be achieved using in-service inspection results or the effect of repair. This is a promising area where it is expected that considerable scope for rationalisation exists. Limitations in more widespread use of such methods is partly due to conservatism, but also due to lack of expedient tools and data. Where fracture mechanics calculations are required as part of the calculations, the detailed stress and material property information required is substantial.

Available resources for safety purposes are always limited. This fact has caused us to take an increasing interest in cost related aspects of offshore projects. An example is the report on economic risk analyses of an offshore field development project by R. Sjong et al in 1987, Ref [7]. Such insight helps us to better adapt requirements to achieve cost effective safety measures.

CONCLUSION

Third party certification is increasingly being specified in legislation for offshore developments. The paper describes some of the practical problems and methods for handling the the third party certification or Certifying Authority role for offshore development projects.

A potential exists for further improvement of certification cost in areas such as project organisation, use of probabalistic techniques for inspection scopes and documentation practices.

REFERENCES

[1] Probabalistic Fatigue Crack Growth Analyses of Offshore Structures, with Reliability Updating Through Inspection. H. O. Madsen et al, A.S. Veritas Research.

[2] Probabalistic Framework for Ice Loads on Fixed Marine Structures. M. Nessim, A. Cormeau, Det norske Veritas (Canada) Ltd July 1988. Report to the Department of Public Works, The Government of Canada.

[3] Optimum Strategy for the Design and Operation of Floating Systems Subjected to Ice and Sea Hazards. Interim Report, Det norske Veritas (Canada) Ltd, October 1988.

[4] The Danish Energy Authorities' Use of Risk Analyses. L. Goldschmidt, G. Beck and F. Bill, Danish Energy Agency.

[5] The Documentation Epidemic. G.A. Drangeid. Article in NOROIL, April 1988.

[6] Floating Production Vessels: Capital Cost Considerations. V. von Hoffman, OTC 5804 May 1988.

[7] Economic Risk Analyses of Offshore Fiel Development Project. R. Sjong, J. Lerheim and H.O. Madsen, A/S Veritas Research report 87-2028, 1987.

Fig. 1 Illustration of Verification Functions versus Component Criticality

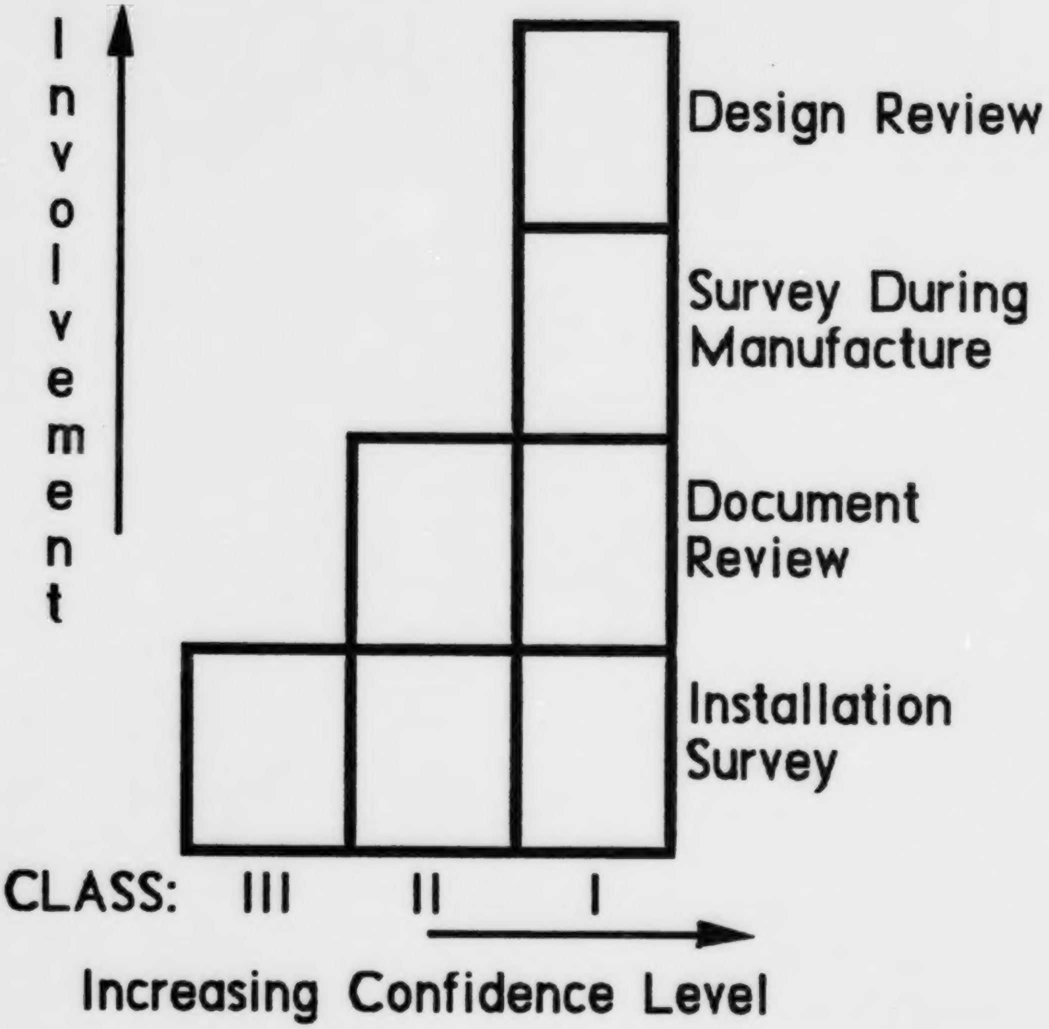

Involvement
Design Review
Survey During Manufacture
Document Review
Installation Survey
CLASS: III II I
Increasing Confidence Level

Fig.2 Perceived Confidence versus type of Material Certificate

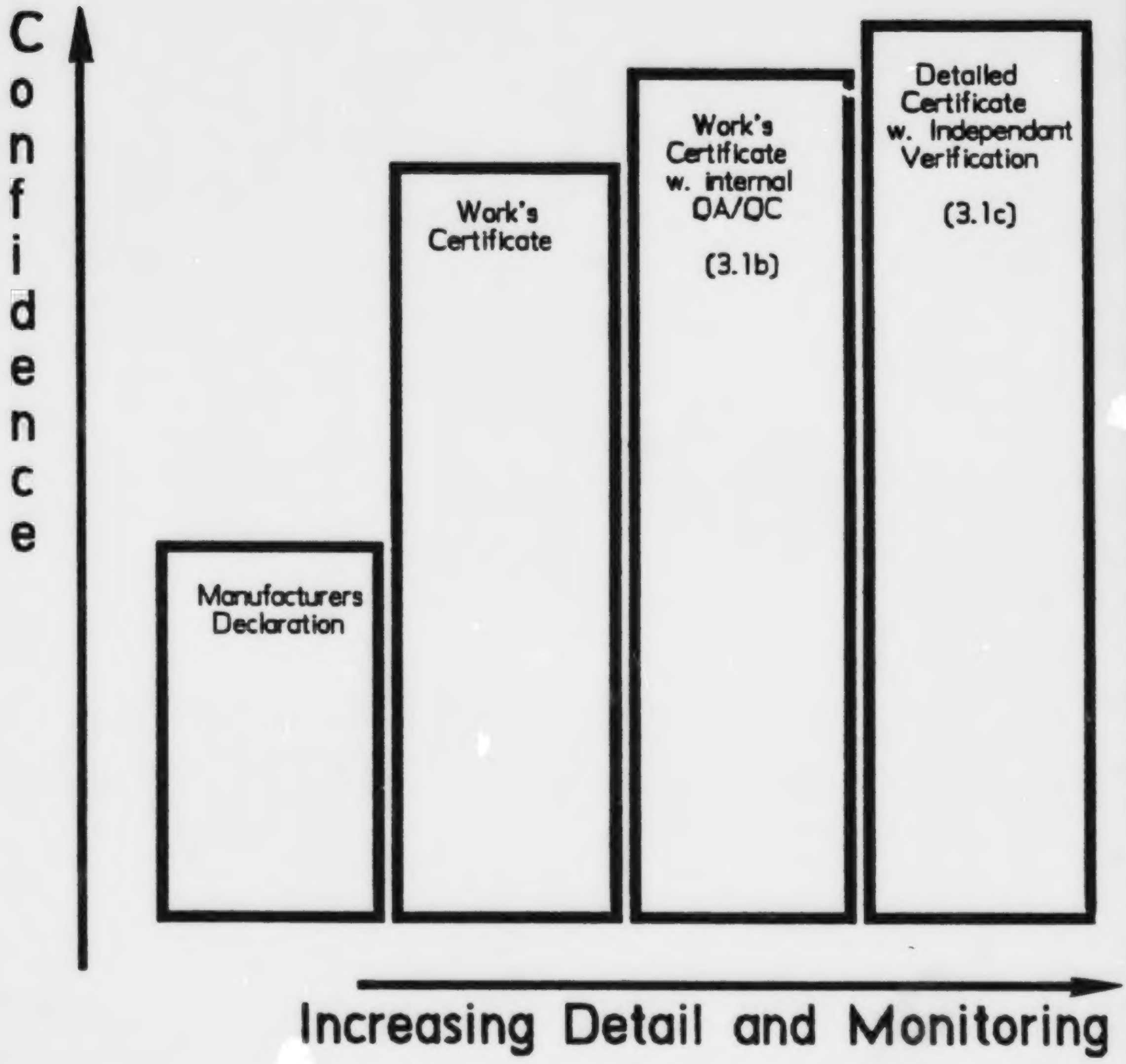

Confidence
Manufacturers Declaration
Work's Certificate
Work's Certificate w. internal QA/QC
(3.1b)
Detailed Certificate w. Independant Verification
(3.1c)
Increasing Detail and Monitoring

Fig. 3 Modification of Survey Scope with QA/QC Implementation

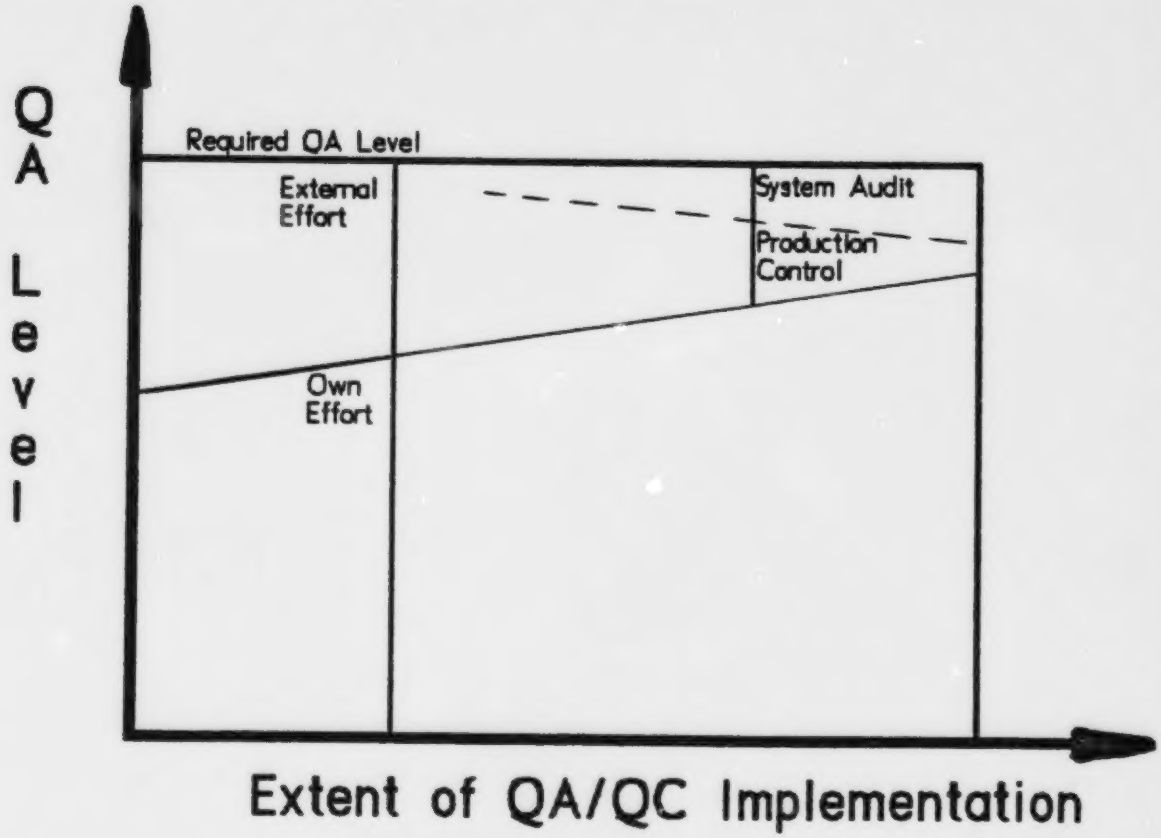
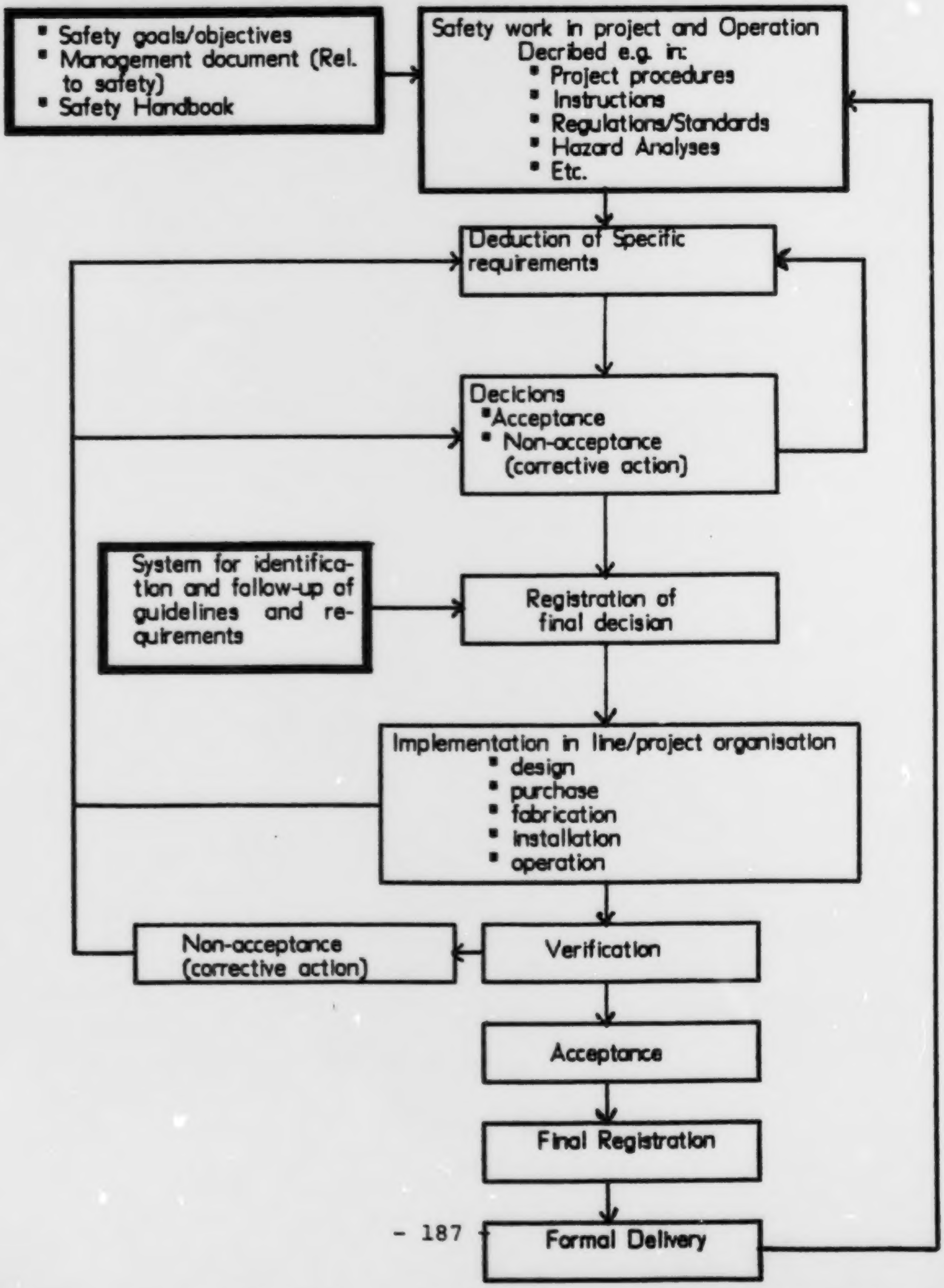

Q
A
L
e
v
e
l
Required QA Level
External
Effort
System Audit
Production
Control
Own
Effort
Extent of QA/QC Implementation

Fig.4 The Safety Management Process



- Safety goals/objectives
- Management document (Rel. to safety)
- Safety Handbook
Safety work in project and Operation Decribed e.g. in:
- Project procedures
- Instructions
- Regulations/Standards
- Hazard Analyses
- Etc.
Deduction of Specific requirements
Decicions
- Acceptance
- Non-acceptance (corrective action)
System for identification and follow-up of guidelines and requirements
Registration of final decision
Implementation in line/project organisation
- design
- purchase
- fabrication
- installation
- operation
Non-acceptance (corrective action)
Verification
Acceptance
Final Registration
Formal Delivery

Fig.5 Database for management of safety requirements

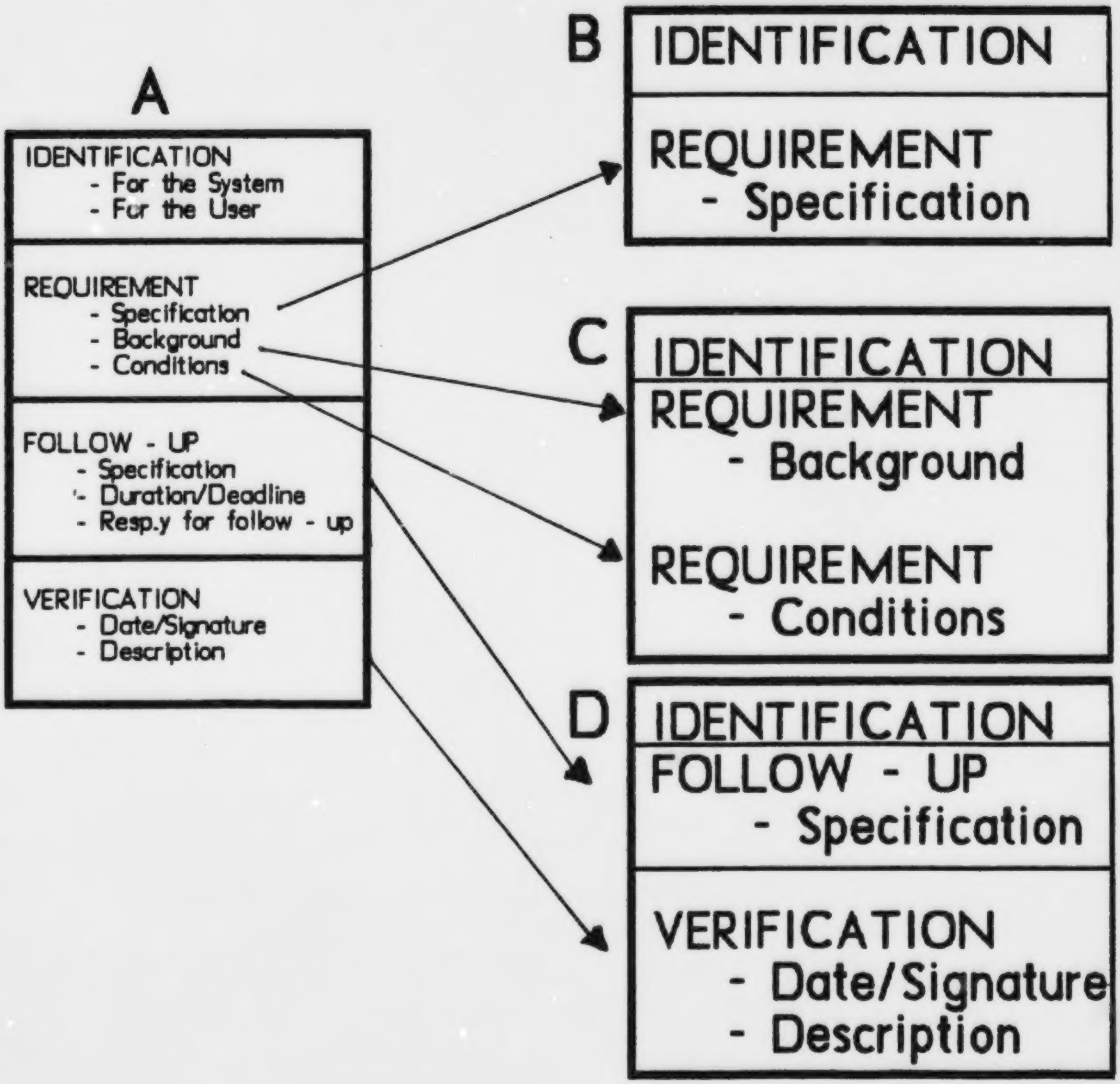
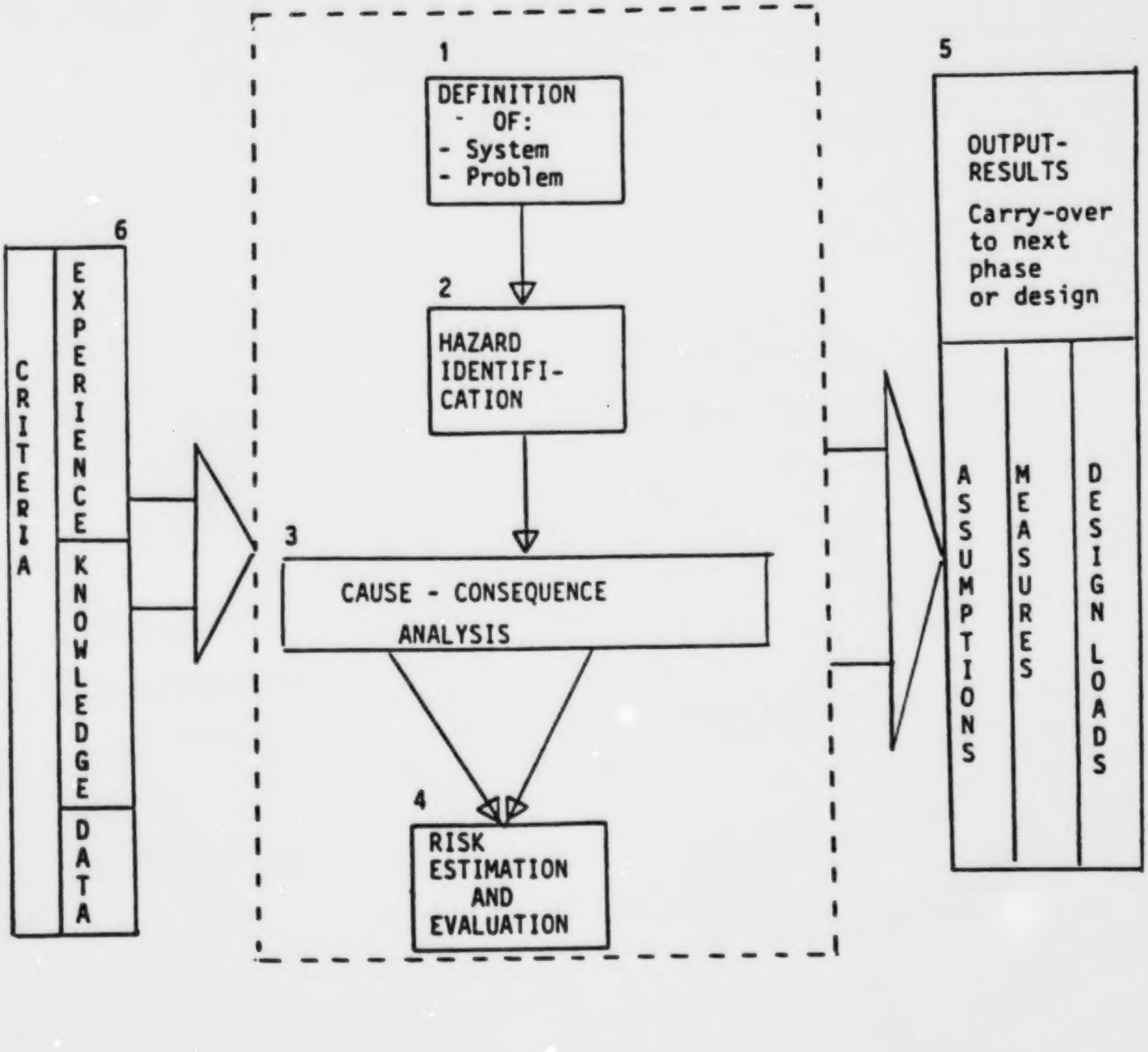

A
IDENTIFICATION
- For the System
- For the User
REQUIREMENT
- Specification
- Background
- Conditions
FOLLOW - UP
- Specification
- Duration/Deadline
- Resp.y for follow - up
VERIFICATION
- Date/Signature
- Description
B
IDENTIFICATION
REQUIREMENT
- Specification
C
IDENTIFICATION
REQUIREMENT
- Background
REQUIREMENT
- Conditions
D
IDENTIFICATION
FOLLOW - UP
- Specification
VERIFICATION
- Date/Signature
- Description

FIG. 6 MODEL FOR RISK ANALYSES


1
DEFINITION OF:
- System
- Problem
2
HAZARD IDENTIFICATION
3
CAUSE - CONSEQUENCE ANALYSIS
4
RISK ESTIMATION AND EVALUATION
5
OUTPUT-RESULTS
Carry-over to next phase or design
ASSUMPTIONS
MEASURES
DESIGN LOADS
6
CRITERIA
EXPERIENCE
KNOWLEDGE
DATA

SPEAKER : J. T. MANNING, BSC, PHD, FICE, FIHT

COMPANY : OFFSHORE CERTIFICATION BUREAU (OCB)

LOCATION : LONDON, ENGLAND

TOPIC : CONSTRUCTION PHASE CERTIFICATION REQUIREMENTS

BIOGRAPHY: Dr. Manning has been involved in the design appraisal, construction supervision and quality control of offshore and marine structures for the past twenty years. He is a partner in the firm of Messrs. Sandberg, Consulting Inspecting and Testing Engineers, who are a member of the consortium forming OCB. He was involved in construction and maintenance aspects of the Central Ninian platform, a concrete gravity structure of 650,000 tonnes, a 300,000 tonne floating dry dock constructed in steel and concrete and many steel jacket structures fabricated in the UK. His involvement in quality assurance and quality control of construction extends to major on-shore projects including Nuclear Power Stations, the Channel Tunnel and City redevelopment through the OCB member, Messrs. Sandberg, who employ approximately 400 staff on all aspects of quality management and testing.

SYNOPSIS

The basis of the U.K. Certification scheme, leading to the issue of certificates of fitness, is outlined. The process of establishing compliance criteria as set out in Guidance Notes and amplified in specifications is briefly explained. Quality Assurance assessments and the principles of inspection and quality control forming part of a quality plan are described in the context of certification.

Some aspects of technical controls for steelwork and concrete construction are identified, and general comments relating to in service inspections of concrete structures are made.

1. INTRODUCTION

In the mid and late 1970's there was considerable U.K. activity in the field of concrete construction for offshore structures for the North Sea. The construction of tower structures for Central Ninian, Brent C, Cormerant, followed from the concrete tank built for the Ekofisk field in 1971. About 6 concrete structures towed from Norwegian yards are also located in U.K. waters. The development of piping and discharge techniques obviated the need for offshore storage and, in spite of fierce commercial competition resulting from the availability of construction locations, concrete structures for the U.K. sector of the North Sea lost favour. There has been a recent revival in the use of concrete for development of shallow gas fields with the construction of a three legged platform for the Ravenspurn field.

Inspite of the lack of construction projects utilising concrete for offshore structures, research and investigation programmes continued and have been of considerable value in the understanding of the behaviour of reinforced and prestressed concrete in a marine environment. Techniques for assessing compatibility of aggregates and cement to produce durable insitu concrete have developed in recent years, as have methods of assessing the performance of reinforced concrete structures.

OCB (Offshore Certification Bureau) was formed in 1976 from groupings of consulting engineers and is authorised by the Secretary of State to issue Certificates of Fitness for Offshore Installations in the U.K. sector of the North Sea and North Atlantic. As general consulting engineers, the parent companies of OCB have wide experience in structural and civil engineering design and supervision in all fields, and particularly in concrete construction. Technical control by Certification is common in many fields as is the growing area of assessment of quality systems. OCB's approach to these tasks, together with brief technical notes on control of steel and concrete construction, and inservice inspections, are described.

2. COMPLIANCE CRITERIA, GUIDANCE NOTES AND SPECIFICATIONS

(a) Regulations

Certification of fixed and mobile Offshore Installations in accordance with the Statutory Instrument 1974/289 Offshore Installations (Construction and Survey) Regulations 1974 (1), is mandatory for oil and gas facilities operating in the U.K. sector of the North Sea and North Atlantic . This document imposes British Government technical regulations for the issue of a Certificate of Fitness. The Certifying Authority acts on behalf of the Secretary of State to survey design and installation and to issue certificates as appropriate. The scope of the Certifying Authorities duties are defined in SI289 and are broadly to ensure compliance with recognised standards.

When satisfied with the documents and information submitted, all the survey declarations and results of independent assessments, the Certifying Authority will issue a Certificate of Fitness if it considers that it is proper to do so. The validity of a Certificate of Fitness is normally for a period of five years from the completion of the last major survey. During the period of the validity of the Certificate, annual surveys must be conducted.

To assist the Certifying Authorities and Owners in the Certification process, the Department of Energy provides Guidance Notes(2) and these are constantly being updated as a result of Safety Notices etc. and to reflect the current state of the art.

Changes/modifications and repairs are constantly taking place on Installations and the Certifying Authority is required to be notified in writing of any alteration, repair or replacement of any part of the Installation, but experience has shown that this does not always happen. Experience has also shown that many failures occur when a system or piece of equipment is recommissioned following maintenance or modification. A systematic safety assessment should be carried out by the owner and reviewed by the Certifying Authority wherever modifications or additions are proposed. A rigorous change control procedure is essential.

As OCB said in its submission to the Burgoyne Committee(3), which was published as submission No. 12 of the Report presented to Parliament in 1980, "Safety must be examined across the conventional boundaries of structural, mechanical, electrical, process, navigational and marine engineering etc. for the Installation as a whole."

To overcome some of these interfaces, the Committee recommended that the role of the Certifying Authority should be extended to cover the complete oil and gas pressurised system from the Down-hole Safety Valve to the shore or tanker connection. Had some of the relatively inexpensive recommendations of that Report been implemented quickly, there would probably have been far fewer accidents in the North Sea.

Examples of where safety related matters are likely to be more closely reviewed in the future are:-

(i) The installation of safety shut-down devices in pipelines.

(ii) The requirement for Safety Assessments from the design stage through all phases to operation, and to be continued during maintenance and modification.

(iii) Operation of process plant, which is generally designed for full stream operation with reduced throughput, or fault and transient conditions. A hazard and operability study and Safety Report should address these aspects and be made a necessary condition of the issuance of the Certificate of Fitness.

(iv) The introduction of more strict change control procedures and monitoring of adherence to these.

(v) Provision of alternative incident control centres for use if the main control room is put out of action.

Many of the recommendations contained in the Burgoyne Report have been incorporated into the Canadian Offshore Regulations, with the scope of the Certifying Authority's responsibility being extended to include down-hole safety valves to shore or tanker connections.

OCB advocates that the Certifiying Authority should be provided with an initial Safety Assessment/Study of the proposed Installation prior to the commencement of detailed design and should be kept appraised of any safety related changes during design, construction and operation and their impact on the Safety Study.

The studies should be aimed at ensuring, for example, that:-

- No single failure prevents the operation of emergency systems

- The reliability claimed for emergency systems are specified, justified and are verified as far as practicable.

- The probability of common-mode failure has been recognised, examined and, where possible, eliminated.

- Use has been made as necessary of diversity, redundancy and segregation in the design of emergency systems.

- Emergency systems have been protected against unauthorised access and against damage.

- Maintenance and test requirements have been taken into account when assessing the reliability and availability of the emergency systems.

- Fire and gas detection systems are properly located and capable of initiating a shut-down.

- All hazardous areas are clearly identified and there is an effective ventilation system to disperse a gas leakage (but not to fan a fire).

This list is by no means exhaustive.

Department of Energy Safety Notice No. 5/89(4) states that, safety assessments should also be carried out to consider the effects of a gas release and explosion on essential systems on the installation. The results of the studies should be discussed with the Certifying Authority.

Although SI 1974/289 does not require the Certifying Authority to assess the safety of operations, it does require the Certifying Authority to review the Operations Manual to ensure that it contains all the information essential to the safe operation of the Installation. There is no requirement in SI 1974/289 for the Certifying Authority to verify or otherwise that the operations are being performed in accordance with the Operations Manual. In many accidental events, a major contributory factor is the failure to have, or to follow instructions.

These are just a few areas of concern that have been highlighted to emphasise the importance of the Certification regime and the way in which Owners and suppliers may make full use of the resources of the Certifying Authorities and the Petroleum Engineering Division of the Department of Energy to eliminate or reduce to acceptable levels, the risks to which the 20,000 offshore workers in the U.K. sector are exposed.

OCB were privileged to undertake in early 1988 a technical review of the draft Canada Oil and Gas Production Installation Regulations for CNOPB. These draft Regulations contain much technical data which will be of value to owners, designers, builders and Certifying Authorities.

(b) U.K. Guidance Notes for the Design, Construction and Certification of offshore Concrete Structures

The draft 4th edition of the U.K. Guidance Notes are dated June 1988 and have been circulated by the Department of Energy to selected parts of the offshore industry for comment. It is hoped that they will be issued in their final form later this year. The particular section on Guidance for Concrete Structures (Section 23) has already been agreed with industry. The specified standard for the design and detailing of reinforced, prestressed and precast concrete work is BS8110.1985(5), although particular clauses relate to environmental conditions, temporary loading, grouting of prestressing tendons, fatigue and assessment of impact damage. A list of the topics covered in the Guidance Notes is included as Appendix A.

In 1976 a jointly funded U.K. Government (through the Department of Energy) and industry research programme entitled "Concrete in the Oceans" was started. This major programme, undertaken in two phases over nine years, was aimed at improving knowledge of behaviour, design and durability of concrete offshore and maritime structures. Investigations were grouped under headings of corrosion, structural aspects and design, fatigue and inspection, and details of the topics covered are given in Appendix B. This programme is now completed and the results of the investigations have been taken into account in the Guidance Notes.

The construction phase is covered in the Guidance Notes in general terms with recommendations for forming joints, concreting in hot and cold weather, maintaining cover to reinforcement and tolerances for various member sizes. The importance of maintaining records during construction is stressed, as is the need for a constant design input to verify that the stage by stage sequencing is compatible with the structure as conceived.

The principles for repair of offshore structures are set out in the Guidance Notes and accepted materials are concrete, cement grouts and mortars and epoxy resins. The use of polymer modified cements and concrete is not recommended. Repair of fire damage is specifically addressed and the importance of identification of temperature and its effect on prestressing steel is noted.

(c) Specifications

The Guidance Notes give a base from which detailed specifications can be prepared. Care has been taken to ensure compatibility of codes and standards as it is important to have consistency of:

(i) Statistics and design events
(ii) Rules for calculating their effect
(iii) Rules for calculating their resistance.

Most Canadian, American, British and French codes are based on limit state, but others use permissible stresses. With limit state considerations, return periods for various events, factors of safety against serviceability and collapse, materials consistency and stress combinations need to be made clear in Regulations, so that similar starting points exist for the designer and Certifying Authority.

Compliance criteria relating to design assumptions and workmanship standards must be readily identifiable. The approach adopted by OCB is to prepare technical reviews in the form of data summaries and quality monitoring plans and to work closely with the operating company and their team.

The materials selection for offshore structural concrete requires particular care. Consideration of compatibility of cement, aggregates and admixtures has become a highly specialised field interfacing geology, chemistry and engineering. The Guidance Notes give general directions on assessment of drying shrinkage, alkali-silica reaction, tricalcium aluminate levels, hydraulic binders, air entrainment and additives, but the overriding statement "the source and characteristics of all materials to be used should be properly investigated" necessitates the involvement of specialists and the Certifying Authority at least one year before construction is planned to commence. This time scale is determined by long-term suitability testing, and a requirement to develop realistic particular specifications reflecting the properties of locally available materials.

3. QUALITY ASSURANCE, INSPECTION AND QUALITY CONTROL

(a) Quality Assurance

During the past decade and as a result of both legislation and the operators' desire to minimise accidents, many firms have reorganised and have introduced new technology, new systems and independent verification to provide them with the assurance that their installations are Fit for Purpose. Several operators have engaged OCB members to conduct independent checks on certain aspects of the design and construction of their installations outside that of the Certification Scheme. Am extract from OCB's operation manual showing the initial organisational controls is included as Appendix C.

The desire of an increasing number of Operators to ensure that the design and construction conforms to requirements is reflected in their insistence on independent checks and the requirement that their contractors and suppliers have effective quality systems in place before being awarded a contract.

Historically, the increasing interest in Quality Assurance and the subsequent introduction of BS5750(6) in 1979, coincided with the second sudden rise in oil prices which resulted in making the exploitation of North Sea oil even more attractive. Oil companies in the U.K. were looking at the rising costs of inspection and reinspection and, whilst realising that inspection was no guarantee of quality, were desperately endeavouring to find contractors who could help them to obtain quality and reduce the inevitable delays of rework.

Following the Government's initiative in launching the National Quality Campaign (7) and the formalisation of training schemes for Quality System Assessors, many contractors and suppliers have been able to formalise their Quality Systems such that they can now ensure and demonstrate that their services and products conform to requirements.

It is recognised that the application of a Quality Assurance programme to the design and construction of an installation does not automatically qualify for the issue of a Certificate of Fitness. Furthermore a Certifying Authority's consideration of any QA scheme cannot be fettered in advance and surveyors need to be given the opportunity to conduct, or ensure there has recently been conducted by a competent person, a thorough independent assessment of each system.

In addition to work to a predetermined quality or surveillance plan, Surveyors and Assessors must be constantly vigilant, to recognise new features and be able to ensure that critical aspects have been identified and flagged for special surveillance during all phases. Innovation is moving at such a pace that only specialist analysis and monitoring of the systems will ensure that the correct controls are employed in a cost effective manner. It is the duty of the Certifying Authority to be satisfied that the internal controls and methodology employed in design, construction and operation is commensurate with innovation to the extent that the completed installation will be satisfactory.

(b) Inspection

SI1974: 289 requires that:

> except where the documents approved or recognised by the Certifying Authority otherwise provide, workmanship and methods of construction shall be, and shall be inspected, in accordance with recognised standards and codes of practice and, without limitation to the generality of the foregoing -
>
> (i) all welding shall be in accordance with a recognised standard or code of practice and performed by suitably qualified persons; and
>
> (ii) concrete shall be prepared and placed in accordance with a recognised standard or code of practice appropriate for a marine environment, by suitably experienced persons and under the direction of a competent person experienced in marine concrete construction work.

Since it is common for operators/engineering contractors to arrange their own inspection, the role of the Certifying Authority often reverts to document verification. A more effective contribution is made where the inspection and certification are combined, with the clear imposition of standards for construction being monitored through contractors' own Quality Assurance Procedures.

(c) Quality Control

The implementation of quality control for concrete construction requires the provision of a fully equipped on-site laboratory operated by trained personnel. Back-up facilities for specialist investigation of cements, aggregates, reinforcement, prestressing steel, metal components, soils and numerous other components need to be available well before construction commences and for regular reference testing. The U.K. Department of Trade and Industry operates a scheme for accreditation of Laboratories, NAMAS(8), and compliance with this is normally specified for testing on public sector work and for major projects. This scheme is about to be extended to on-site laboratories which is indicative of the increasing implementation of the principles set in the Government White Paper Comnd. 8621 "Standards Quality and International Competitiveness". (9)

4. TECHNICAL CONTROLS

(i) Steelwork

Processes involving jointing of steelwork normally involves four activities, i.e. production in rolling mills, fabrication of sub assemblies, fabrication and assembly at on-shore location and hook-up off shore.

Jacket and topside assemblies are often fabricated in different locations and work involves various steel grades and, occasionally, castings. Consistency of standards is controlled through welding procedures, welding procedure approval tests, welding operator approval records, visual inspection and NDT. Traceability of materials, components and consumables is essential and inevitably the maintaining of strict documentation is a burden on contractors. NDT results, with compliance criteria, defects and repairs during fabrication are inspected by Certifying Authorities as are records of fit-up and visual inspections. Protective treatment is similarly controlled through inspection and test plans. The industry is increasingly utilising higher strength steels and the welding of these to ensure satisfactory performance under fatigue loading in potentially aggresive environments needs careful metallurgical consideration. The behaviour of mooring chains and their performance under sustained load is an area currently under investigation in the U.K.

(ii) Concrete

The selection of materials for concrete construction involves setting up an investigation in which some tests require monitoring over a long period. Alkali silica reaction (ASR) is attracting particular attention in many countries and an understanding of the expansion mechanism in saline conditions is still at the research stage.

Traditionally, quality control is based on results from cubes made and tested with the same mix as that used in the structure. There is an increasing requirement to establish properties such as density, heat of hydrations and potential expansion on larger samples representative of parts of the structure, and for post construction coring to correlate results with cube samples and member dimensions. Aspects of concrete construction for marine environments which are increasingly being introduced in U.K. are (i) the use of epoxy coated reinforcement (ii) post construction coatings to reduce surface penetration and (iii) the use of hydraulic binders (ground granulated blast furnace slag or pulverised fuel ash) used separately or combined with ordinary Portland cement. Materials which may become more prevalent with concrete construction in the future are glass fibre reinforced cements, parafil carbon fibres for prestressing, manufactured lightweight aggregates and silica fume binders.

Prestressing components utilise very high strength drawn steel wires in ducts anchored by castings. The cement grouting of ducts after stressing requires careful control and monitoring to ensure long-term corrosion protection. The level of cathodic protection for prestressing components cannot be accurately predetermined and many authorities favour isolation from the reinforcement and external steelwork which may be separately protected. Warnings have been expressed on the possible danger of over-protection of prestressing steel resulting in hydrogen cracking.

5. IN SERVICE INSPECTIONS

In service inspection of steel structures is well documented and subsea techniques for cleaning, crack detection, visual inspection and monitoring are constantly improving. Inspection of concrete structures is less well reported as deterioration has not been a problem. The following comments related to underwater inspection of concrete structures summarise the current state of the art:-

(i) There are two distinct zones for inspection involving differing techniques, i.e. atmospheric (splash zone and above) and permanently submerged.

(ii) Predetermined reference markers in the structure are required to determine locations for underwater surveillance.

(iii) Total inspection of concrete surfaces is impossible and unnecessary due to redundant nature of structural form.

(iv) Particular areas should be subjected to planned inspections, e.g. infill anchorage zones, scour areas, penetrations through walls, pipe fixings. This will involve local removal of marine growth.

(v) The construction history should be reviewed when preparing in service inspection plans. Areas of repair, poor construction joints, junctions of reinforced/prestressed concrete structure should be identified as investigation zones.

(vi) An understanding of the classification and identification of typical blemishes visible on the surface of concrete underwater is essential.

(vii) Inspection techniques for reinforced concrete utilising electro potential mapping and resistivity methods (above water level) are available.

(viii) Confidence levels can be increased by the provision of sacrificial samples which are inspected and tested at regular intervals.

Instrumentation techniques involving inclinometers and stress measurements to give information of the behaviour of foundations and localised members such as skirts, spider beams and topside equipment are normally incorporated and monitored by the owner and Certifying Authority. Long-term vertical movement of the platform due to consolidation of soil or well depletion should be monitored against a remote datum rather than water levels. Inspection techniques involving underwater video cameras are well suited to concrete structures but, as noted on (ii) above location of inspection areas needs careful referencing. Similar techniques are also utilised for the control of damage assessment and underwater repairs.

CONCLUSIONS

Structural concrete construction on a massive scale, with volumes of the order of half a million cubic metres has become commonplace around the world in recent years. The development of quality control systems for such projects has in turn become a specialist part of the industry, utilising trained staff from disciplines wider than civil engineering, viz. chemists, geologists, physicists and concrete techologists. Techniques for monitoring insitu concrete construction based on density measurement (to supplement traditional cube making) are being developed, and the sciences of cement chemistry and geology are able to provide an in depth understanding of the hardening mechanism for concrete. Commercial pressures, the desire to win local materials and the uniqueness of the constituents at each location necessitate careful study and an extensive testing programme before structural concrete commences. The Certification Authority should be involved at an early stage in the formulation of quality plans for all aspects of concrete construction, i.e. quarry management, cement suppliers, mixing and placing proposals, reinforcement and prestressing components, curing, quality control maintenance of records and commissioning. Similarly, proposals for inservice inspections should be addressed at the design stage so that instrumentation and areas for periodic monitoring can be suitably incorporated in the detailing. Although the main duty of the Certifying Authority is to act in a policing role, this is invariably achieved in a spirit of close technical co-operation to the benefit of the project. It is propounded that owners, operators, designers and constructors, in addition to legislative bodies, should benefit from technical input and control made available through certifying schemes.

REFERENCES

(1) Statutory Instruments 1974 No. 289 Offshore Installations, The Offshore Installations (Construction and Survey) Regulations 1974. ISBN 0-11-040289-8.

(2) Department of Energy, Offshore Installations: Guidance on Design Construction and Certification. Draft Fourth Edition:1988.

(3) Burgoyne Report. Report of the Committee on 'Offshore Safety'. Cmmd 7841.

(4) Department of Energy Safety Notice 'Gas Releases from Production and Compression Systems'. 21 February 1989.

(5) BS8110: 1985: 'Structural Use of Concrete (3 parts).

(6) BS5750: 1987 'Quality Systems' (5 parts).

(7) Department of Trade and Industry, National Quality Campaign. Launched 1982.

(8) NAMAS - National Measurement Accreditation Service. NAMAS Concise Directory, 3rd Edition May 1987.

(9) White Paper Cmmd.8621: 'Standards, Quality and International Competitiveness'. HMSO (London) 1982.

APPENDIX A - ITEMS COVERED BY GUIDANCE NOTES

Department of Energy

Offshore installations: Guidance on design, construction and certification

Draft: Fourth edition - 1988

Contents

(For detailed tables of contents, please refer to relevant Section)

1 Definitions and interpretations
2 Principles of certification
3 Independent assessment of design and method of construction
4 Surveys
5 Documentation
6 Quality assurance
7 Abandonment (decommissioning and removal) of fixed Offshore Installations
8 Operations manual
10 Installation layout
11 Environmental considerations
12 Corrosion protection
13 Fire protection
14 Site investigations
15 Loads
20 Foundations
21 Steel
22 Pile/sleeve connections
23 Concrete
24 Materials other than steel or concrete
30 Floating Installations
31 Stability, watertight integrity and ballasting
32 Station keeping
33 Self-elevating installations (jack-up units)
40 Electrical equipment
41 Instrumentation (no text)
42 Mechanical equipment
43 Well control equipment
44 Gas flares and cold vents
50 Living accommodation
51 Heating and ventilation
52 Noise and vibration
53 Illumination
54 Decks, stairways etc.
55 Helicopter landing area
60 Structural repairs
90 Emergency facilities
91 Emergency shutdown systems

Appendices

A11 Environmental considerations
A12 Corrosion protection
A21 Steel
A22 Pile/sleeve connections
A23 Concrete
A43 Well control equipment
A52 Noise and vibration

Appendix B Bibliography

Appendix C Addresses

Alphabetical Index

DRAFT

DRAFT

APPENDIX B

U.K. RESEARCH PROGRAMME "CONCRETE IN THE OCEANS"

Phase I	1976 - 1983
Phase II	1979 - 1985
Value	£1.3 m (actual)

TOPICS COVERED

Corrosion

Fundamental mechanisms of corrosion of steel reinforcement in concrete immersed in seawater.

Rate of penetration through concrete of the agents causing corrosion.

Location of corrosion cells in marine concrete structures.

Exposure of test specimens at Portland and Loch Linnhe.

Definition of conditions where corrosion of steel reinforcement in concrete under water is undetectable by visual inspection.

Criteria for cover and control of cracking in underwater concrete.

Structural aspects and design

Theoretical methods of designing concrete cylinders and shell elements against implosion due to high hydrostatic pressures.

Effects of temperature gradients on storage cells with different percentages of reinforcement.

Assessment of impact damage on cell roofs.

Fatigue

Effects of fatigue on offshore and maritime concrete structures.

Fatigue of reinforcement in concrete submerged in seawater.

Fatigue of sections of repaired concrete.

Inspection

Surveys of existing concrete offshore and marine structures.

Review of resistivity and potential mapping techniques.

Experimental development of such techniques.

Classification of blemishes which are found on the surface of concrete under water.

Finally, a Coordinating Report on the whole programme was prepared to bring together the main results and conclusions and present them in a form which can be more readily used by designers, constructors and operators of offshore and maritime concrete structures.

Publications

Offshore Technology Report series by HMSO for the U.K. Department of Energy.

TABLE OF CONTENTS

1.0 POLICY STATEMENT AND FOREWORD

2.0 ORGANISATION, DUTIES AND RESPONSIBILITIES
Organisation Chart
Board of Control
Management Committee
Job Descriptions - Key Personnel

3.0 MEMBER COMPANY RESPONSIBILITIES AND INTERFACES
Merz & McLellan
Rendel Palmer & Tritton
Harris & Sutherland
Burness Corlett & Partners
Messrs Sandberg
Summary of Primary and Secondary Responsibilities
Intercompany Interfaces
Subcontracting:- OCB to Member Companies

4.0 STANDARDS AND PROCEDURES, IDENTIFICATION AND CONTROL
List of Procedures, Location and Control
List of Company Standards, Location and Control
Standard for Procedure Preparation and Control

5.0 THE UK CERTIFICATION SCHEME
History
Controlling Legislation
Interfaces with other Legislative Bodies
Department of Energy Guidance Notes
Continental Shelf Notices
Safety Notices
Safety Alerts

6.0 CERTIFICATION EXECUTION
- The Lead Surveyor
- Certification Planning
- New Build - Fixed
- New Build - Floating
- Existing, Uncertified - Floating
- Change of Certifying Authority
- Ongoing Certification, Planning
- Types of Surveys
- Certification Documentation
- Certificate of Fitness
- Non-Exclusive Surveyors

7.0 EQUIPMENT AND MATERIALS CERTIFICATION
- Criticality Assessment of Equipment and Materials
- Typical Criticality Ratings for Equipment
- Rationalisation of Inspection
- Independent Design Review Certificates
- Certificates of Conformity

8.0 GENERAL ADMINISTRATION
- Communications Control and Distribution
- Accounting and Timekeeping/Expenses
- Budget Preparation and Control
- Meetings - Internal
- Meetings - External
- Meetings - Department of Energy
- Conference Attendance and Information Dissemination
- Insurances
- Register of Surveyors
- List of H.O. Files
- Technical Data and Library
- Personnel
- Training

9.0 MARKETING AND SALES
- Proposal Preparation and Submission
- Market Research

SPEAKER : TOR HENRIK STAVNES

COMPANY : INECO A/S

LOCATION : NORWAY

TOPIC : BENEFITS OF DOCUMENTATION CONTROL

BIOGRAPHY: Mr. Stavnes was educated at Tonsberg Economical College, Norway, in 1971; University of Lyon, Faculte de Lettre, France, in 1972-73; University of Lausanne, Hautes Etudes Commercial, Switzerland, in 1974-75; and Military Experience as an officer in the Norwegian Army.

Professional experience started at Statfjord "A", Mobil Exploration Norway Inc., Cost Engineer (consultant) 1977-79; Statfjord "B", Mobil Exploration Norway Inc., Document Administration Supervisor (consultant) 1979-82; Statfjord "C", Mobil Exploration Norway Inc., Document Adminstration Supervisor (consultant) 1982-85; Oseberg A/B, Norsk Hydro A.S., Document Administration Supervisor (consultant) 1985-87; Oseberg C, Norsk Hydro A.S., Document Administration Supervisor (consultant) 1987-89; Magnesium Project/Becancour, Quebec, Norsk Hydro A.S., Advisor Technical Documentation (consultant) 1988

INTRODUCTION

DOCUMENTATION PRODUCED IN A MAJOR DEVELOPMENT PROJECT SHALL SERVE THE FOLLOWING PURPOSES

- CONCEPTUAL EVALUATION
- TECHN. BASE FOR ENGINEERING AND SUPPL. OF EQUIPM.
- TECHN. BASE FOR CONSTR. AND INSTALLATION
- VERIFICATION OF WORK DONE (MC/COMMISSIONING)
- OPERATION OF INSTALLATION
- MAINTENANCE OF INSTALLATION (incl. EMERGENCY SITUATIONS)
- MATERIAL/PRODUCT QUALITY

IN A LARGE OFFSHORE DEVELOPM. PROJ. AN ESTIMATED

- 10-15000 ENGINEERING DOCUMENTS

ARE ORIGINATED BY
- COMPANY
- SUPPLIER
- ENGINEERING CONTRACTOR
- FABRICATION CONTRACTOR
- HOOK UP/OFFSHORE INST. CONTRACTOR

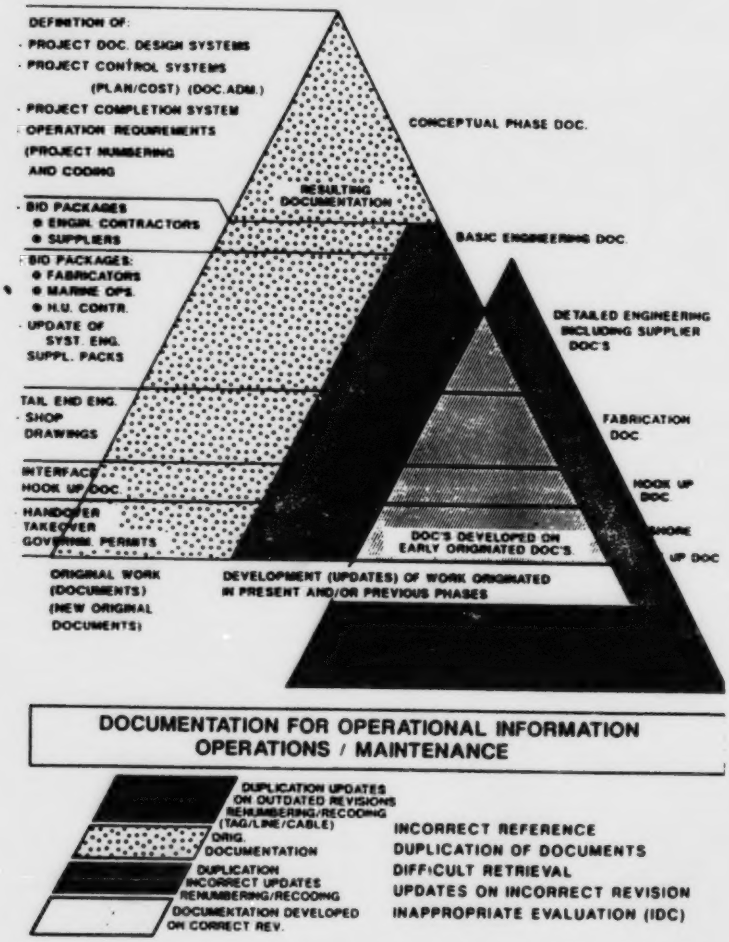
IN ADDITION COMES

- 15-20000 TEST/INSPECTION RECORDS HAND-/TAKEOVER CERTIFICATIONS
- LIMITED NUMBER GOVERNMENTAL PERMITS DOC.

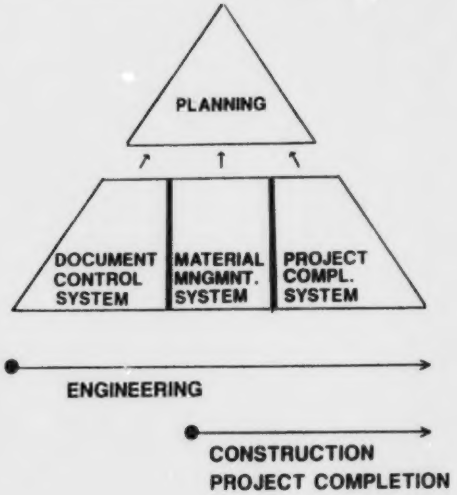
WITH REGARD TO THE ENGINEERING DOCUMENTATION THE FOLLOWING APPLY:
OF THE 15000 DOCUMENTS A MAJOR PART IS GENERATED FROM A LIMITED NUMBER OF DOCUMENTS - 2-3000.

THIS CAN BE ILLUSTRATED AS FOLLOWS:

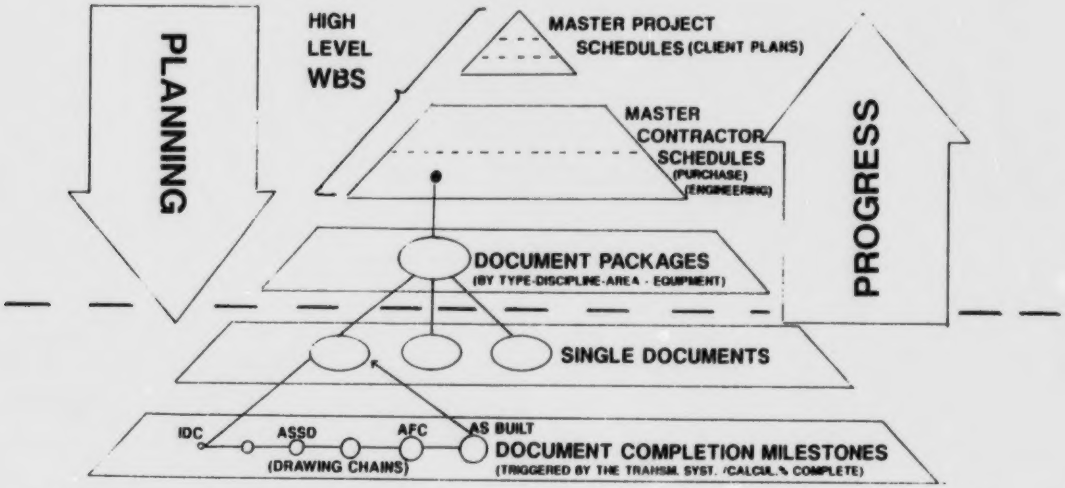
INTRODUCTION Cont.


DEFINITION OF:
· PROJECT DOC. DESIGN SYSTEMS
· PROJECT CONTROL SYSTEMS
(PLAN/COST) (DOC.ADM.)
· PROJECT COMPLETION SYSTEM
· OPERATION REQUIREMENTS
(PROJECT NUMBERING
AND CODING
RESULTING DOCUMENTATION
CONCEPTUAL PHASE DOC.
· BID PACKAGES
● ENGIN. CONTRACTORS
● SUPPLIERS
BASIC ENGINEERING DOC.
· BID PACKAGES:
● FABRICATORS
● MARINE OPS.
● H.U. CONTR.
· UPDATE OF SYST. ENG. SUPPL. PACKS
DETAILED ENGINEERING INCLUDING SUPPLIER DOC'S
TAIL END ENG.
· SHOP DRAWINGS
FABRICATION DOC
INTERFACE HOOK UP DOC.
HOOK UP DOC.
· HANDOVER TAKEOVER GOVERNM. PERMITS
SHORE
UP DOC
DOC'S DEVELOPED ON EARLY ORIGINATED DOC'S.
ORIGINAL WORK (DOCUMENTS) (NEW ORIGINAL DOCUMENTS)
DEVELOPMENT (UPDATES) OF WORK ORIGINATED IN PRESENT AND/OR PREVIOUS PHASES
DOCUMENTATION FOR OPERATIONAL INFORMATION
OPERATIONS / MAINTENANCE
DUPLICATION UPDATES ON OUTDATED REVISIONS RENUMBERING/RECODING (TAG/LINE/CABLE)
ORIG. DOCUMENTATION
DUPLICATION INCORRECT UPDATES RENUMBERING/RECODING
DOCUMENTATION DEVELOPED ON CORRECT REV.
INCORRECT REFERENCE
DUPLICATION OF DOCUMENTS
DIFFICULT RETRIEVAL
UPDATES ON INCORRECT REVISION
INAPPROPRIATE EVALUATION (IDC)

STATUS COLLECTORS FOR THE PROJECT PLANNING SYSTEM


PLANNING
DOCUMENT CONTROL SYSTEM
MATERIAL MNGMNT. SYSTEM
PROJECT COMPL. SYSTEM
ENGINEERING
CONSTRUCTION
PROJECT COMPLETION

THE DOCUMENT ADMINISTRATION SYSTEM / PROGRESS RECORDING


PLANNING
HIGH LEVEL WBS
MASTER PROJECT SCHEDULES (CLIENT PLANS)
MASTER CONTRACTOR SCHEDULES (PURCHASE) (ENGINEERING)
PROGRESS
DOCUMENT PACKAGES (BY TYPE-DISCIPLINE-AREA - EQUIPMENT)
SINGLE DOCUMENTS
IDC
ASSD
AFC
AS BUILT
DOCUMENT COMPLETION MILESTONES (TRIGGERED BY THE TRANSM. SYST. /CALCUL.% COMPLETE)
(DRAWING CHAINS)

TO MEASURE PRODUCTIVITY / AUTOMATED PROGRESS RECORDING ON THE DOCUMENT LEVEL IS REQUIRED

INTRODUCTION Cont.

THIS ILLUSTRATION INDICATES THAT AN APPLIED DOCUMENTATION CONTROL SYSTEM WILL BE AN EFFECTIVE TOOL FOR MANAGING PROJECT DEVELOPMENT THROUGH ALL ITS PHASES PROVIDED OTHER SYSTEMS AS DEFINED ARE ADEQUATELY DEVELOPED AND COORDINATED

i.e. PROJECT CONTROL SYSTEM
PLANT COMPLETION SYSTEM

I WILL NOW GO THROUGH THIS IN DETAIL WITH A SERIES OF OVERHEADS OUTLINING EMPHASES PUT ON

- AUTHORITY REQUIREMENTS
- COST
- INEFFECTIVE USE
- EARLY DEFINITION
  PROJECT NUMBERING AND CODING
- DOCUMENT CONTROL IN GENERAL
- COMPUTERIZED DOC. CONTROL SYSTEM

INTRODUCTION Cont.

THE COMPANY / RESPONSIBLE OPERATOR'S REQUIREMENTS FOR PROJECT DOCUMENTATION SHALL:

REFLECT AND SUPPLEMENT
THE AUTHORITY REQUIREMENTS

FOR

DESIGN -●- FABRICATION -●- INSTALLATION

INTRODUCTION Cont.

COST

EXAMPLE 15 SITES

WHEN THE SITE TEAM IS ESTABLISHED AT SITE, SITE TEAM SHALL RECEIVE 1 SET OF CONTROLLED MANUALS AND PROCEDURES

150 Manuals (each Site + Contractor) x 15 Sites
= 2250 Manuals x à 30 Cdn a copy = 67,500 Cdn
15 Manuals (Coding/MC/Pres./Comm.) x 200 PO's
= 3000 Manuals x à 30 Cdn a copy = 90,000 Cdn
Total = 157,500 Cdn

DUE TO DEFINITION BY COMPANY
LET CONTRACTOR COPY HIMSELF, GIVE OUT 1 COPY ONLY

INTRODUCTION Cont.

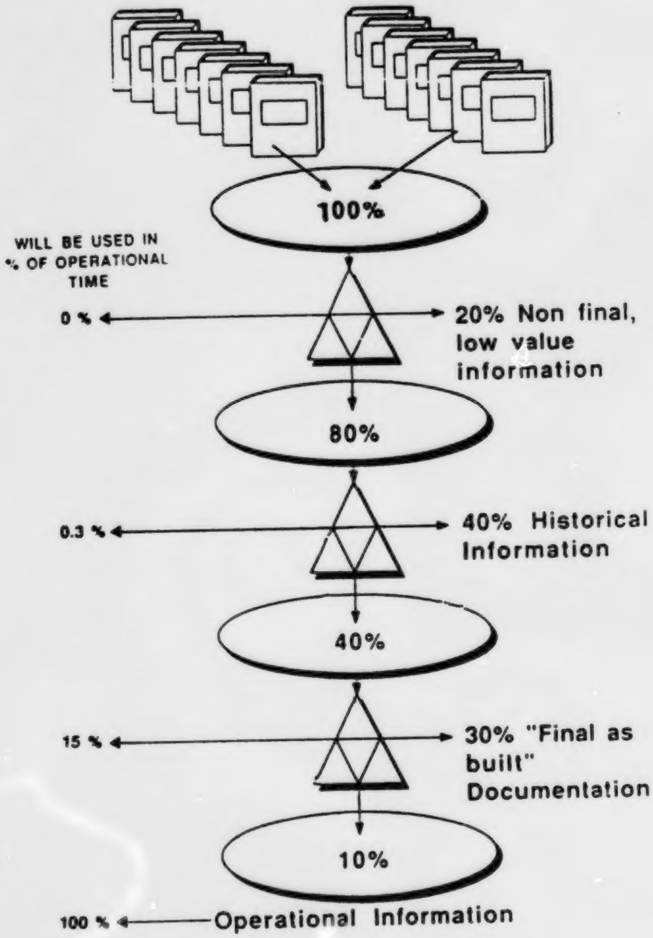
THE DOCUMENTATION SHALL BE:

- IDENTIFIED
- RECORDED
- MAINTAINED
- RETRIEVED
- RETAINED

THE REQUIREMENTS SHALL BE SEEN AS PART OF

COMPANY'S QUALITY ASSURANCE REQUIREMENTS

TECHNICAL DOCUMENTATION REQUIRED IN THE OPERATION PHASE (OPERATION / MAINTENANCE AND REFERENCE DATA)


100%
WILL BE USED IN % OF OPERATIONAL TIME
0 %
20% Non final, low value information
80%
0.3 %
40% Historical Information
40%
15 %
30% "Final as built" Documentation
10%
100 %
Operational Information

INTRODUCTION Cont.

80 % OF ALL OPERATIONS
BREAKDOWNS ARE CAUSED
BY THE HUMAN FACTOR

(Fil. Dr. ALAN D. SWAIN)

INTRODUCTION Cont.

COST

FROM THE MANAGEMENT LEVEL DOWN
TO EACH PROJECT MEMBER EMPHASIS
MUST BE PUT ON

COST - CONSCIOUSNESS

DIRECT COST ⇨ ACCUMULATED COST

ACT LOCALLY · THINK TOTALLY

INTRODUCTION Cont.

COST

- LARGE VOLUME;   AS BUILT REQUIREMENTS

  Advise:

  RENTENATION BY CONTRACTOR
  (BUT AVAILABILITY BY COMPANY)

  Example Oseberg

- EARLY DEFINITION OF A DOCUMENT CONTROL SYSTEM

INTRODUCTION Cont.

COST:

NUMBER OF DOCUMENTS:

FINAL AS BUILT / OSEBERG PHASE 1:

ENGINEERING DRAWINGS: 65 000 (INCL.VENDOR)

NUMBER OF PAGES DOCUMENTS: 800 000

WEIGHT: 8 000 KG (8 TONS)

WIDTH IN METERS: 200 M

INTRODUCTION Cont.

COST

DUE TO LATE DEFINITION OF PROJECT NUMBERING AND CODING.
DEFINITION BY COMPANY:
THE VARIOUS (EP / EPC) ENGINEERING CONTRACTORS WILL CAUSE:

- COSTLY RENUMBERING/RECODING ACTIVITIES
  TO MEET OPERATIONS REQUIREMENTS
    - OPERATION OF PLATFORM SYSTEMS
    - MAINTENANCE OF PLATFORM SYSTEMS
    - SPARE PART SYSTEM

INTRODUCTION Cont.

INEFFECTIVE USE

DUE TO:

- UNNECESSARY COPYING / DISTRIBUTION
  POORLY DEFINED DISTRIBUTION / MISSING CLEAR RESTRICTIONS
- DUPLICATION OF DOCUMENTS
  THROUGHOUT THE VARIOUS PROJECT PHASES
- UPDATES MADE ON OUTDATED REVISIONS
- TIME CONSUMING RETRIEVAL
- INSUFFICIANT/INAPPROPRIATE EVALUATION BY KEY PERSONNEL (IDC/COMMENTS)

INTRODUCTION Cont.

IMPROVEMENT

- EARLY DEFINITION OF PROJECT NUMBERING AND CODING REQUIREMENTS
- COMPUTERIZED INTEGRATED DOCUMENT CONTROL SYSTEM
- COMPUTERIZED INSTALLATION COMPLETION SYSTEM

II PROJECT NUMBERING AND CODING

OPERATOR SHOULD AS PART OF HIS QUALITY ASSURANCE REQUIREMENTS CARRY OUT AN EARLY DEFINITION OF

PROJECT NUMBERING AND CODING SYSTEMS

IN FORM OF A

PROJECT STANDARD

NUMBERING AND CODING MANUAL

II Cont.

THE MANUAL SHOULD BE DEVELOPED TO SERVE THE LONG TERM NEEDS FOR NUMBERING AND CODING BY

- SUPPLIERS
- ENGINEERING CONTRACTORS (EP/EPC)
- FABRICATION CONTRACTORS (SITES/YARDS)
- HOOK UP CONTRACTOR
- OFFSHORE INSTALLATION CONTRACTOR

TO MEET NUMBERING AND CODING REQUIREMENTS BY

- OPERATION
- MAINTENANCE

II Cont.

THE STRUCTURES AND VALUES PRESENTED
IN THE MANUAL SHOULD BE

MANDATORY

FOR ALL PARTIES RESPONSIBLE FOR ORIGINATING
DOCUMENTATION IN THE PROJECT

II Cont.

THE MANUAL SHOULD INCLUDE NUMBERING AND CODING REQUIRED FOR:

- **ADMINISTRATIVE DOCUMENATION (Procedures, Work Instrucions, Contracts, Procurements Packages, etc.)**
- **TECHNICAL DOCUMENTATION (Drawings, Documents, Manuals)**
- **TAG / LINE / CABLE CODING (Syntax + Block Numbering)**
- **FABRICATION DETAIL CODING (Weld, Hook Up Coding)**
- **SPARE PART / PIECE CODING**
- **PRESERVATION / MECHANICAL COMPLETION / COMMISSIONING WORK PACKAGE CODING**

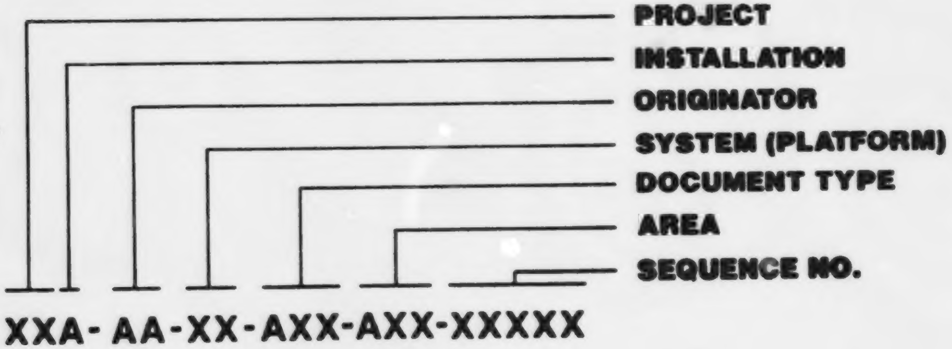
II Cont.

THE PRINCIPLE

ALL PROJECT ENTITIES SHOULD BE GIVEN A

Ⓐ UNIQUE IDENTIFICATION NUMBER

EXAMPLE:
UNIQUE ID/
DOC.NO.



PROJECT
INSTALLATION
ORIGINATOR
SYSTEM (PLATFORM)
DOCUMENT TYPE
AREA
SEQUENCE NO.

XXA- AA-XX-AXX-AXX-XXXXX

II Cont.

AND BE REFERENCED WITH

Ⓑ CLASSIFICATION DATA

KEY DESCRIPTIVE DATA / CROSS REFERENCES

EXAMPLE:	**· COST / WBS CODE**	40.05.100
	· HOOK UP CODE	A1
	· LEAD TAG NUMBER	LI 6301 HH
	· PO NUMBER	6301-C0I-A01

II Cont.

A STRICTLY CONTROLLED CHANGE PROCEDURE:

- AMENDMENTS TO THE MANUAL
- ADDITIONS
- DELETIONS

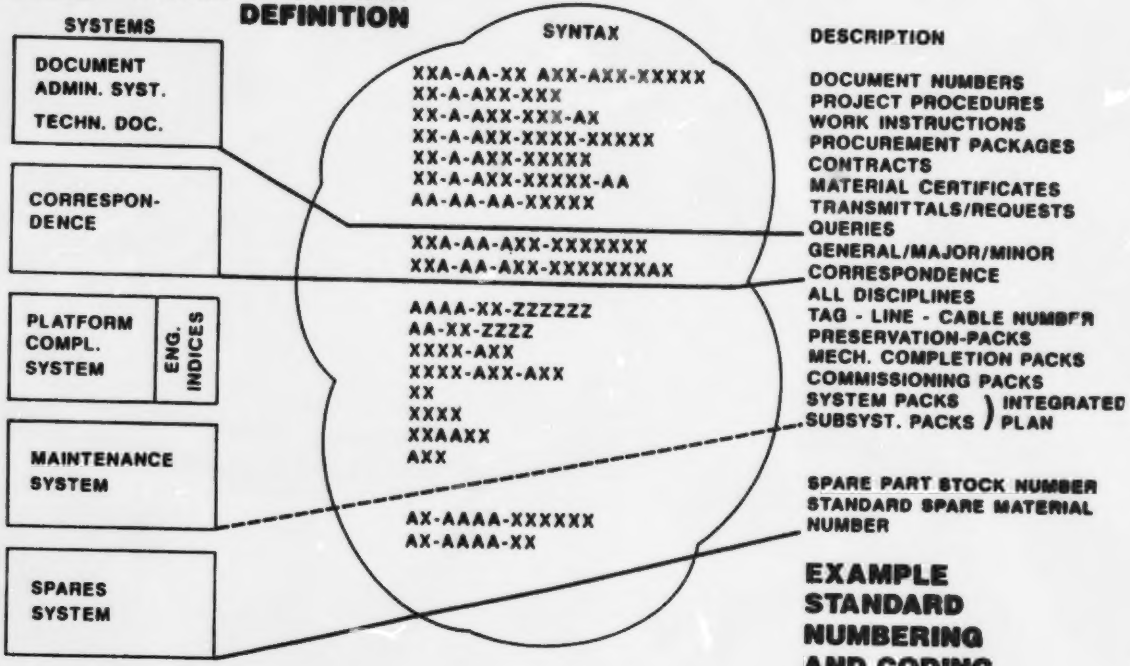
MAY ONLY BE MADE AFTER APPROVAL IS OBTAINED BY COMPANY

- VARIATION / CHANGE QUERIES

- SHOULD BE PROPERLY CIRCULATED FOR COMMENTS BY ONE STRONG NUMBERING AND CODING COORDINATOR (COMPANY)

- NUMBERING AND CODING RESPONSIBILITY SHOULD BE IMPLEMENTED BY ONE COORDINATOR WITHIN EACH MAJOR PROJECT AREA.

II Cont. EXAMPLE SYNTAX DEFINITION


SYSTEMS
DOCUMENT ADMIN. SYST.
TECHN. DOC.
CORRESPON-DENCE
PLATFORM COMPL. SYSTEM
ENG. INDICES
MAINTENANCE SYSTEM
SPARES SYSTEM
SYNTAX
XXA-AA-XX AXX-AXX-XXXXX
XX-A-AXX-XXX
XX-A-AXX-XXX-AX
XX-A-AXX-XXXX-XXXXX
XX-A-AXX-XXXXX
XX-A-AXX-XXXXX-AA
AA-AA-AA-XXXXX
XXA-AA-AXX-XXXXXXX
XXA-AA-AXX-XXXXXXXAX
AAAA-XX-ZZZZZZ
AA-XX-ZZZZ
XXXX-AXX
XXXX-AXX-AXX
XX
XXXX
XXAAXX
AXX
AX-AAAA-XXXXXX
AX-AAAA-XX
DESCRIPTION
DOCUMENT NUMBERS
PROJECT PROCEDURES
WORK INSTRUCTIONS
PROCUREMENT PACKAGES
CONTRACTS
MATERIAL CERTIFICATES
TRANSMITTALS/REQUESTS
QUERIES
GENERAL/MAJOR/MINOR
CORRESPONDENCE
ALL DISCIPLINES
TAG - LINE - CABLE NUMBER
PRESERVATION-PACKS
MECH. COMPLETION PACKS
COMMISSIONING PACKS
SYSTEM PACKS
SUBSYST. PACKS
INTEGRATED PLAN
SPARE PART STOCK NUMBER
STANDARD SPARE MATERIAL NUMBER

EXAMPLE STANDARD NUMBERING AND CODING

III

HAVING ESTABLISHED THE BASIS DOCUMENT FOR ALL DOCUMENTATION PRODUCTION WE MUST ENSURE THAT

ALL DOCUMENTATION PRODUCTION IS

- PLANNED
- PROGRESS RECORDED
- MOVEMENTS RECORDED

IN A CONTROLLED MANNER

THIS CONTROL WILL ENABLE THE PROJECT TO FUNCTION EFFICIENTLY

III Cont.

DOCUMENT CONTROL WILL COORDINATE

- IDENTIFICATION
- RESPONSIBILITY
- DISTRIBUTION REQUIREMENTS
- FORMAT / NUMBER OF COPIES
- UPDATE / CHANGE PROPOSALS
- FILE KEYS / INDEXING
- RETRIEVABILITY
- ACHIEVE REQUIREMENTS
- SECURITY
- FINAL DISPOSITION OF DOCUMENTATION DURING AND AT PROJECT COMPLETION

IV - COMPUTERIZED DOCUMENTATION CONTROL SYSTEM

RECOMMENDATION IS MADE
TO THE OPERATION OF A

CENTRAL
COMPUTERIZED
DOCUMENTATION
ADMINISTRATION SYSTEM

IV Cont.

THE DOCUMENTS VARIE IN:

- **SIZE**
- **MEDIA**
- **TYPE**
- **DISTRIBUTION**
- **IMPORTANCE**
- **RETAINMENT**

THIS MEANS THAT EACH DOCUMENT MUST BE TREATED

INDIVIDUALLY

IV COMPUTERIZED DOCUMENTATION CONTROL SYSTEM

**AN EFFICIENT AND WELL RUN DOCUMENT
ADMINISTRATION/CONTROL SYSTEM PLAYS
A CENTRAL ROLE IN KEEPING:**

- PLAN AND PROGRESS MEASUREMENT
- MOVEMENT RECORDING
- FILES AND REGISTERS UPDATED

IV Cont.

DECIDING A SYSTEM PHILOSOPHY

- EFFECT FOR FUTURE STRATEGY i.e.

STATFJORD - SINGLE SYSTEM (5-10) DEVELOPMENT IN EACH PROJECT)

OSEBERG - 4-5 SYSTEMS TO BE TRANSFERRED TO ONE DATABASE RUN BY OPERATIONS

FUTURE = 1 SYSTEM ALL PHASES NB

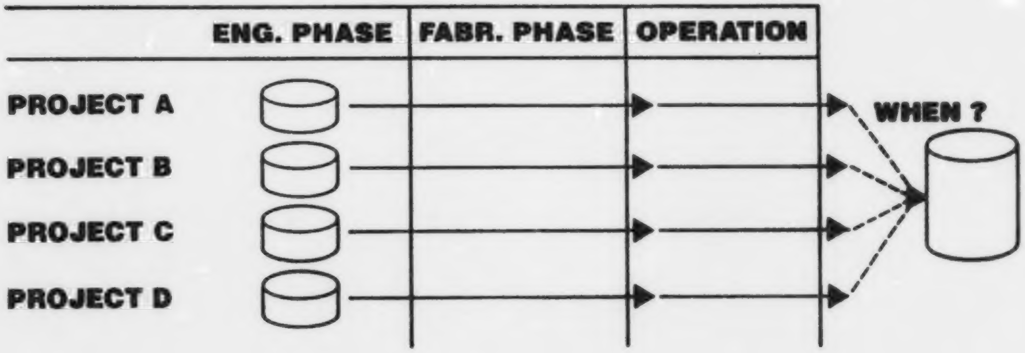
↓

ALL PROJECTS

IV Cont.

EXAMPLE:

A MAJOR NORWEGIAN OIL COMPANY OPERATES

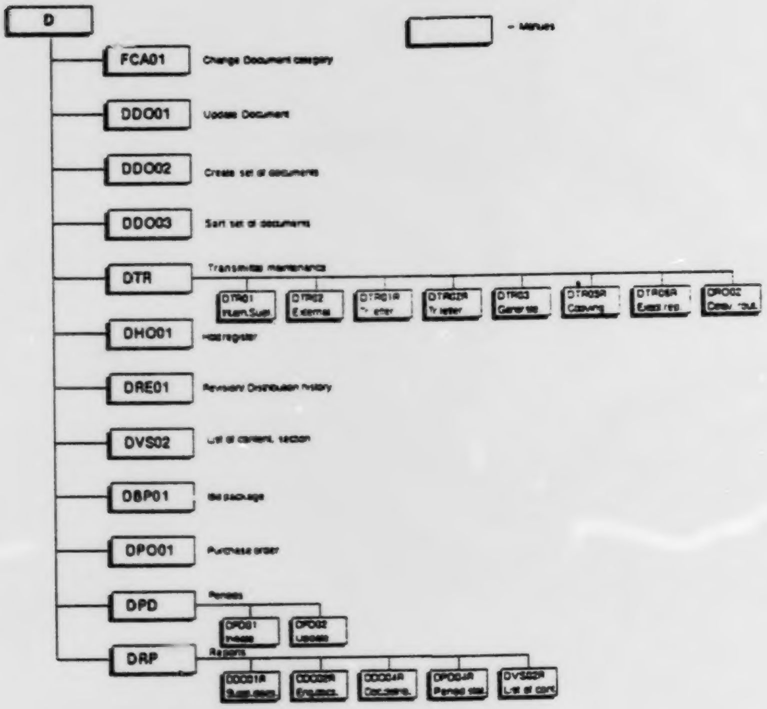

ENG. PHASE
FABR. PHASE
OPERATION
PROJECT A
PROJECT B
PROJECT C
PROJECT D
WHEN ?

IV Cont.

ONE DATABASE HANDLING

- MAIN PROJECT DOCUMENTATION
- ALL SUB PROJECTS DOCUMENTATION
- CONTRACTORS DOCUMENTATION
- SUPPLIERS DOCUMENTATION

Program hierarchy diagram of the Document Administration system.



D
- Menues
FCA01
Change Document category
DDO01
Update Document
DDO02
Create set of documents
DDO03
Sort set of documents
DTR
Transmittal maintenance
DTR01
DTR02
External
DTR01R
DTR02R
Tr letter
DTR03
DTR03R
Copying
DTR06R
DHO01
Hold register
DRE01
Revision/ Distribution history
DVS02
List of content, section
DBP01
Bid package
DPO01
Purchase order
DPD
Periods
DPO01
DPO02
Update
DRP
Reports
DDO01R
DDO02R
DDO04R
DPO04R
Period stat.
DVS02R
List of cont.

Overview of the modules

1. FCA01 - Change Document category.
- Used to change the current Document Category

2. DDO01 - Update Document.
- Document maintenance routine. Used to create and modify documents.

3. DDO02 - Create set of documents.
- Routine for creating set of documents based on selections by the user. This set may later be used in other programs.

4. DDO03 - Sort set of documents.
- Routine used to sort a set of documents on user specified sort criteria.

5. DTR - Transmittal maintenance menu.

6. DTR01 - Supplier internal transmittal.
- Used to create supplier transmittals for internal distribution.

7. DTR02 - External transmittal.
- Used to create external supplier and engineering transmittals.

8. DTR01R - Transmittal letter, internal supplier.
- Used to print out transmittal letters for a set of supplier transmittals.

9. DTR02R - Transmittal letter, external transmittal.
- Used to print out transmittal letters for external supplier and engineering transmittals.

10. DTR03 - Generate Distribution Transmittals
- Used to generate transmittal for documents flagged for distribution.

11. DTR05R - Print Copying request list.
- Used to print a copying request list for a selection of transmittals.

12. DTR06R - Transmittal exeption report.
- Used to list delayed transmittals etc.

13. DRO02 - Delay on transmittal routing.
- Used to list transmittals with delay on routing.

14. DHO01 - Holds.
- Used to maintain holds on documents.

15. DRE01 - Revision/Distribution history.
- Used to display the revision/distribution history for a document.

16. DVS02 - List of content, Section.
- Used to maintain the list of contents for final as built documentation.

Overview of the modules

17. DBP01 - Bid pack.

18. DP001 - Purchase order.

19. DPD - Period menu.

20. DPD01 - Initiate period.
- Used to initiate periods used for status reporting on documents.

21. DPD02 - Update current period.
- Used to update current status period.

22. DRP - Report menu.

23. DDO01R - Supplier document register.
- Used to list a selection of supplier documents.

24. DDO02R - Engineering document register.
- Used to list a selection of engineering documents.

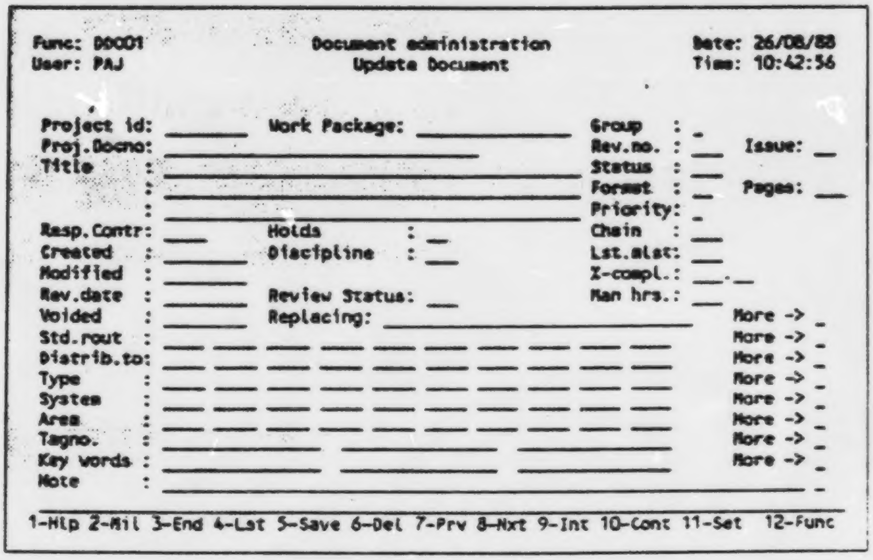
25. DDO04R - Document distribution report.
- Used to generate a distribution report for documents.

26. DPD04R - Status report, period.
- Used to list status per Bid package type/Discipline per status period.

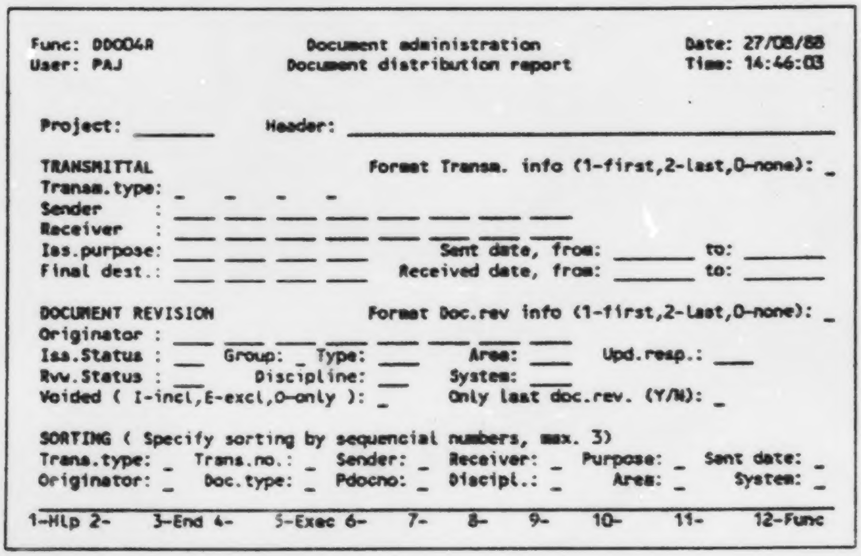
27. List of contents.
- Used to print the list of contents.

Relations between the modules

Almost all modules in the Document Administration system are highly integrated. To check these relations, verification rules are built into the system (eg. Before distributing a document by the transmittal system, the document must have been be recorded by the document update routine).

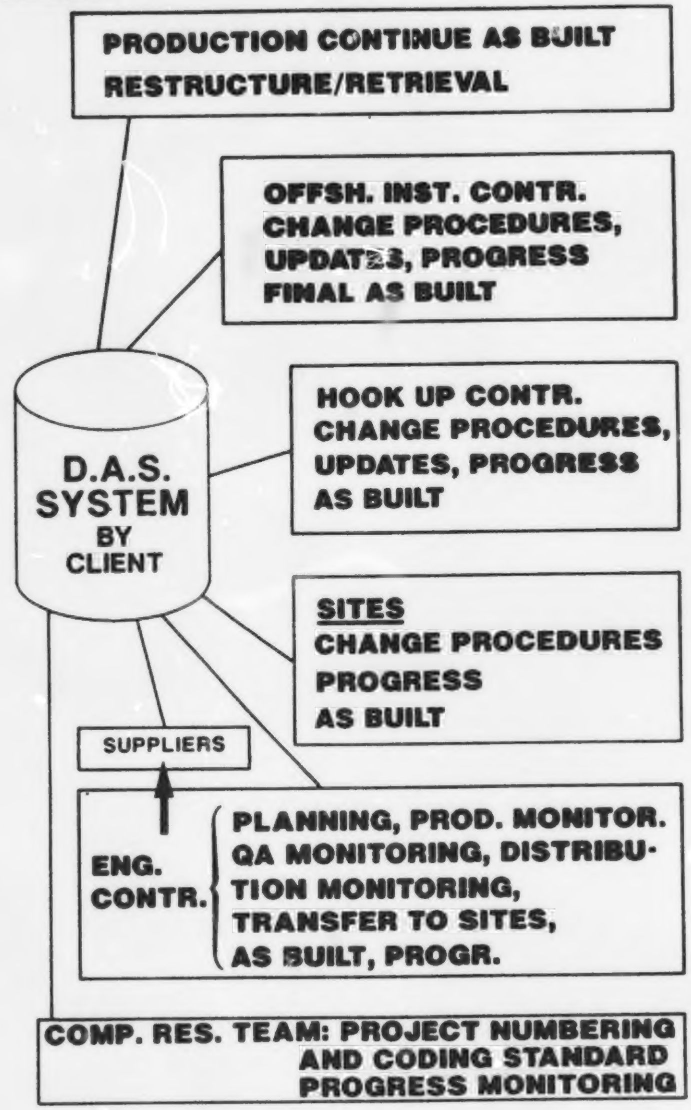


```
Func: DD001              Document administration                  Date: 26/08/88
User: PAJ                    Update Document                      Time: 10:42:56

 Project id: _______  Work Package: _____________  Group    : _
 Proj.Docno: ___________________________          Rev.no.  : __   Issue: __
 Title     : _______________________________________  Status   : __
           : _______________________________________  Format   : _    Pages: ___
           : _______________________________________  Priority: _
 Resp.Contr: ___      Holds      : _                 Chain    : __
 Created   : _______  Discipline : __                Lst.mlst: __
 Modified  : _______                                 %-compl.: __._
 Rev.date  : _______  Review Status: __              Man hrs.: __
 Voided    : _______  Replacing: ___________________________     More -> _
 Std.rout  : ___ ___ ___ ___ ___ ___ ___ ___ ___ ___            More -> _
 Distrib.to: ___ ___ ___ ___ ___ ___ ___ ___ ___ ___            More -> _
 Type      : ___ ___ ___ ___ ___ ___ ___ ___ ___ ___            More -> _
 System    : ___ ___ ___ ___ ___ ___ ___ ___ ___ ___            More -> _
 Area      : ___ ___ ___ ___ ___ ___ ___ ___ ___ ___            More -> _
 Tagno.    : _____________ _____________ _____________           More -> _
 Key words : _____________ _____________ _____________           More -> _
 Note      : ______________________________________________________________ _
________________________________________________________________________________
1-Hlp 2-Mil 3-End 4-Lst 5-Save 6-Del 7-Prv 8-Nxt 9-Int 10-Cont 11-Set  12-Func
```



```
Func: DD004A              Document administration                 Date: 27/08/88
User: PAJ               Document distribution report              Time: 14:46:03

 Project: _______   Header: _______________________________________________

 TRANSMITTAL                     Format Transm. info (1-first,2-last,0-none): _
 Transm.type: _   _   _   _
 Sender     : ___ ___ ___ ___ ___ ___ ___ ___
 Receiver   : ___ ___ ___ ___ ___ ___ ___ ___
 Iss.purpose: ___ ___ ___ ___       Sent date, from: _______  to: _______
 Final dest.: ___ ___ ___ ___   Received date, from: _______  to: _______

 DOCUMENT REVISION               Format Doc.rev info (1-first,2-Last,0-none): _
 Originator : ___ ___ ___ ___ ___ ___ ___ ___
 Iss.Status : __  Group: _ Type: ___     Area: ___    Upd.resp.: ___
 Rvw.Status : __      Discipline: __    System: ___
 Voided ( I-incl,E-excl,O-only ): _     Only last doc.rev. (Y/N): _

 SORTING ( Specify sorting by sequencial numbers, max. 3)
 Trans.type: _  Trans.no.: _  Sender: _  Receiver: _  Purpose: _  Sent date: _
 Originator: _  Doc.type: _  Pdocno: _  Discipl.: _     Area: _    System: _
________________________________________________________________________________
1-Hlp 2-    3-End 4-    5-Exec 6-    7-    8-    9-    10-     11-     12-Func
```

IV Cont.



PRODUCTION CONTINUE AS BUILT
RESTRUCTURE/RETRIEVAL

OFFSH. INST. CONTR.
CHANGE PROCEDURES,
UPDATES, PROGRESS
FINAL AS BUILT

D.A.S.
SYSTEM
BY
CLIENT

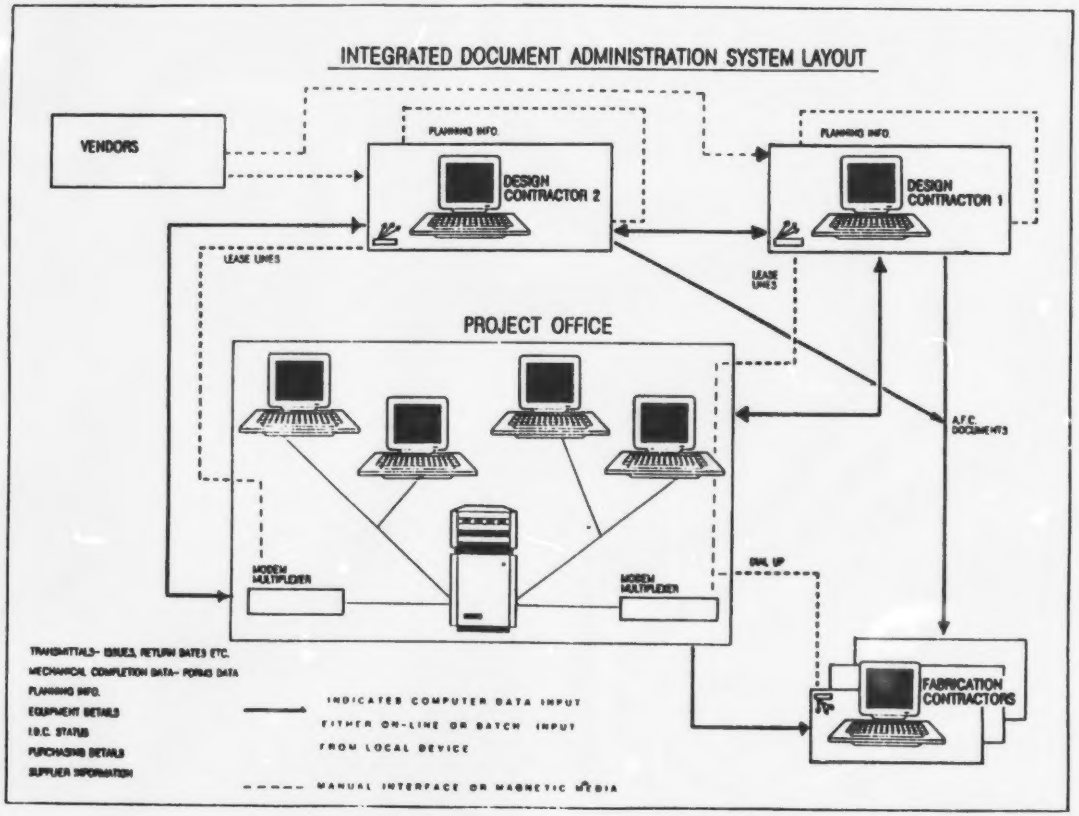
HOOK UP CONTR.
CHANGE PROCEDURES,
UPDATES, PROGRESS
AS BUILT

SITES
CHANGE PROCEDURES
PROGRESS
AS BUILT

SUPPLIERS

ENG. CONTR.
PLANNING, PROD. MONITOR.
QA MONITORING, DISTRIBUTION MONITORING,
TRANSFER TO SITES,
AS BUILT, PROGR.

COMP. RES. TEAM: PROJECT NUMBERING
AND CODING STANDARD
PROGRESS MONITORING



INTEGRATED DOCUMENT ADMINISTRATION SYSTEM LAYOUT

VENDORS
PLANNING INFO.
DESIGN CONTRACTOR 2
PLANNING INFO.
DESIGN CONTRACTOR 1
LEASE LINES
LEASE LINES
PROJECT OFFICE
A.F.C. DOCUMENTS
MODEM MULTIPLEXER
MODEM MULTIPLEXER
DIAL UP
FABRICATION CONTRACTORS
TRANSMITTALS- ISSUES, RETURN DATES ETC.
MECHANICAL COMPLETION DATA- FORMS DATA
PLANNING INFO.
EQUIPMENT DETAILS
I.D.C. STATUS
PURCHASING DETAILS
SUPPLIER INFORMATION
INDICATES COMPUTER DATA INPUT EITHER ON-LINE OR BATCH INPUT FROM LOCAL DEVICE
MANUAL INTERFACE OR MAGNETIC MEDIA

IV Cont.

GENERAL SYSTEM REQUIREMENTS:

- HIGH PERFORMANCE
  (COST EFFECTIVE USE OF HARDWARE)
- USER EFFICIENCY ↓
  - ● QUICK ACCESS TO DATA (NON NONSENCE)
  - ● FLEXIBILITY IN USE (USER GROUPS ADAPTABLE)
  - ● HIGHLY DEVELOPED SYNTAX CHECKS
  - ● ONLINE HELP FACILITIES
  - ● HIGH CAPACITY INPUT (PUNCHING) FUNCTIONS
    - EFFECTIVE SCREEN PICTURES
    - USER INTERFACE

IV Cont.

GENERAL SYSTEM REQUIREMENTS :

- NUMBER AND CODING SYSTEM INDEPENDANT
  - EACH PROJECTS NUMBERING AND CODING REQUIREMENTS ARE DEFINED AND MAINTAINED AS PARAMETERS INTHE D.A.S. SYSTEM

IV Cont.

GENERAL SYSTEM REQUIREMENTS :

- SECURITY
  - ● SAFETY WITH REGARD TO
    - PREVENT UNAUTHORIZED PERSONNEL
      - ○ TO RETRIEVE DATA
      - ○ CHANGING/CORRUPTING DATA
    - USER RELATED SECURITY SYSTEM DETAILED ON:
      - ○ FUNCTION
      - ○ SCREEN
      - ○ DATA FILE
      - ○ DATA FIELDS
- EFFICIENT (NON EXPENSIVE) SYSTEM MODIFICATION/MAINTENANCE BY USE OF 4th Generation Language Tools

IV Cont.

SYSTEM REQUIREMENTS

RETRIEVAL BY:

- FORMATED CLASSIFICATION ELEMENTS
- FREETEXT

IV Cont.

SYSTEM REQUIREMENTS

- ENSURE IMPLEMENTATION OF STANDARD NUMBERING AND CODING REQUIREMENTS

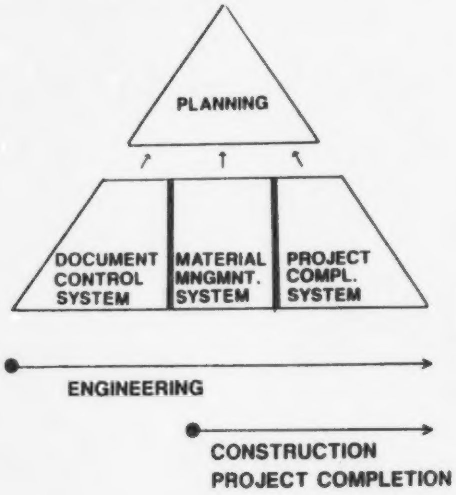
REF. STANDARD PROJECT NUMBERING
AND CODING MANUAL

IV Cont.

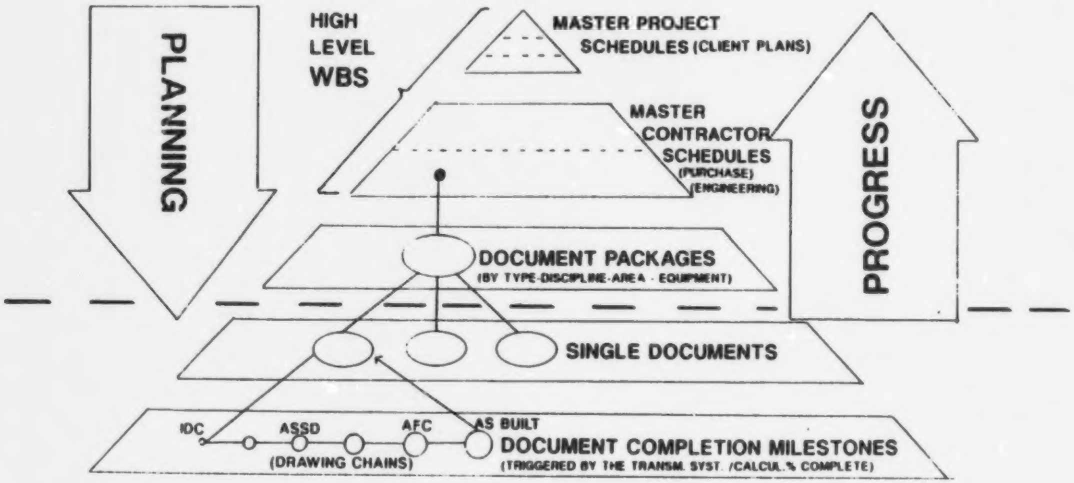
PLANNING OF DOCUMENTATION PRODUCTION

- **RECORDING OF LOW LEVEL DOCUMENT PRODUCTION PLANS**
- **COLLECTOR OF ACTUAL PROGRESS STATUS OF DOC. PRODUCTION**
- **FEEDING THE COMPANY AND/OR CONTRACTOR PLANNING SYSTEM (PLANNED/FORECAST/ACTUAL DATES/REPORT % COMPLETE)**

STATUS COLLECTORS FOR THE PROJECT PLANNING SYSTEM


PLANNING
DOCUMENT CONTROL SYSTEM
MATERIAL MNGMNT. SYSTEM
PROJECT COMPL. SYSTEM
ENGINEERING
CONSTRUCTION
PROJECT COMPLETION

THE DOCUMENT ADMINISTRATION SYSTEM / PROGRESS RECORDING



PLANNING

HIGH
LEVEL
WBS

MASTER PROJECT
SCHEDULES (CLIENT PLANS)

MASTER
CONTRACTOR
SCHEDULES
(PURCHASE)
(ENGINEERING)

PROGRESS

DOCUMENT PACKAGES
(BY TYPE-DISCIPLINE-AREA - EQUIPMENT)

SINGLE DOCUMENTS

IDC
ASSD
AFC
AS BUILT
(DRAWING CHAINS)

DOCUMENT COMPLETION MILESTONES
(TRIGGERED BY THE TRANSM. SYST. /CALCUL.% COMPLETE)

**TO MEASURE PRODUCTIVITY / AUTOMATED PROGRESS RECORDING
ON THE DOCUMENT LEVEL IS REQUIRED**

IV Cont.

IDENTIFICATION OF QA (QUALITY ASSURANCE) REQUIREMENTS :

- **IDENTIFICATION OF IDC (INTER DISCIPL. CHECK)**
- **IDENTIFICATION OF INTERFACE CONTRACTOR CHECK**
- **IDENTIFICATION OF COMPANY APPROVAL**
- **IDENTIFICATION OF RESPONSIBILITY**

⬇

CHANGE RESPONSIBILITY

THE FULFILLMENT OF THE QA REQUIREMENTS IS ENSURED/FOLLOWED UP BY THE TRANSMITTAL SYSTEM

IV Cont.

TRANSMITTAL SYSTEM

- MONITORING (IDC) INTER DISCIPLINE CHECK
- MONITORING INTER CONTRACTOR DISTRIBUTION
- MONITORING COMPANY APPROVAL
- MONITORING CHANGE PROCEDURES (CAN's, SITE QUERIES)
- MONITORING TRANSFER OF RESPONSIBILITY

IV Cont.

DISTRIBUTION MONITORING

(TRANSMITTAL SYSTEM)

- IDENTIFICATION OF TRANSMITTAL

  - **ID NUMBER**
  - **PURPOSE**
  - **SENDER**
  - **RECEIVER**
  - **ACKNOWLEDGEMENT**

IV Cont.

SYSTEM SUPPORT FOR :

- FINAL DOCUMENTATION (AS BUILT)
  - **SUPPLIER PACKAGES**
  - **FABRICATION CONTRACTS**
  - **ENGINEERING CONTRACTORS**

IV Cont.

REPORT GENERATOR / QUERY MODULE

(HARDCOPY/REPORTS) (SCREEN PICTURE)

- DOCUMENT REGISTER
- PROGRESS REPORTS
- DISTRIBUTION REPORTS
- CHANGE PROCEDURE REPORTS
- DEVIATION REPORTS
- AS BUILT INDEXES
- AD HOC - REPORT GENERATION I.E. CONNECT TAG/DOC. NUMBERS

REPORTS MUST BE AVAILABLE DIRECT QUERY / ALL USERS

SPEAKER : **LARRY ROGERS**

COMPANY : **QUALITY MANAGEMENT INSTITUTE (CSA)**

LOCATION : **TORONTO, ONTARIO, CANADA**

TOPIC : **IT'S A JUNGLE OUT THERE**

BIOGRAPHY: Larry Rogers is the president of Quality Management Institute, a not-for-profit division of Canadian Standards Association which provides a nationally-recognized, independent, third-party auditing authority for quality assurance system registration.

He has over 25 years of experience in senior management positions in the steel fabricating and welding industries. Before this, he spent a number of years in the electronics and textile industries as a Chief Industrial Engineer (grad McMaster 1956).

Never has the phrase "It's a Jungle Out There" held as much meaning as it does today. With the challenges presented by Free Trade, combined with the introduction of yet another series of quality assurance standards, the rules of the jungle continue to change and increase in complexity. Companies are finding that they need a map to guide them through this complex jungle; and the map is an effective quality assurance system-- shared by operators, contractors and vendors alike.

The objective is clear: **QUALITY for all Canadian-supplied products and services**

I think we'd all agree that there are countries today who enjoy a quality reputation; I think we'd also agree that we're not one of them. Competition is now global and what was acceptable in Canada during the last forty years is no longer good enough. Global customers demand assurance that quality is built-in. They expect that suppliers will provide **the right thing, right the first time, on time, all the time, and always to their satisfaction!** You may be thinking, 'well so do Canadians'. You're right of course, but typically we buy goods made elsewhere to get it!

Let's take a snapshot look at what some of our global competitors are doing:

EC 1992: With 12 multinational drivers; British Telecommunications, Nestle, Fiat, Philips, Olivetti, Electrolux, Bull, Ciba-Geigy, Renault, Volkswagen, Robert Bosch and Avions Marcel Dessault-Breguet, the European Community is organizing to be a quality powerhouse, and a most demanding customer. In fact, 1992 really begins today; already we have organizations in Canada responding to European demands for verifiable compliance to ISO 9000.

BRITAIN: In 1978, Britain determined that the cost of "poor quality" to Britain was 10 billion pounds per year, or 10% of the GNP. In 1983, UK sponsored a massive program to promote quality--to date 5000 companies have registered their quality assurance systems with BSI, positioning themselves to compete effectively in the global marketplace.

JAPAN: Synonomous with quality.

PACIFIC RIM: Korea's "K" Mark assures their customers of quality and function! Korean companies, along with companies from Singapore and Taiwan, have already approached Canada for registration of their quality assurance systems to CAN3-Z299.

AUSTRALIA and NEW ZEALAND: Both nations visited us for a number of weeks to learn about registration in their countries. They have since adopted the ISO series of standards for their national standard, and organizing their own Registration Program.

BRAZIL: Brazil currently supplies several major corporations in Canada, and has approached QMI for assistance in developing their own national registration program.

MEXICO: The sleeper. The Maquiladora Corporation is an industrial giant in Mexico, starting hundreds of new factories in Tijuana alone last year. Their base philosophy is 'quality'. Canadian government representatives have been approached to buy from them. As an alternative trade partner with the US, Mexico is becoming a serious competitor.

UNITED STATES: Canada's free trade partner has adopted ISO. Their reputation is not one of quality yet but any sleeping giant much be watched!

So how do the 'quality' nations do it. Typically, their standards for quality are very high and enforced consistently. In other words, they use a system to assure quality and work very hard to maintain it. But which standard? There are hundreds of quality assurance standards in the world. Which one provides the system you need? I believe that Canada's own CAN3-Z299, combined with the international ISO 9000 series of standards, equips Canadian companies with the tools to compete effectively anywhere in the world.

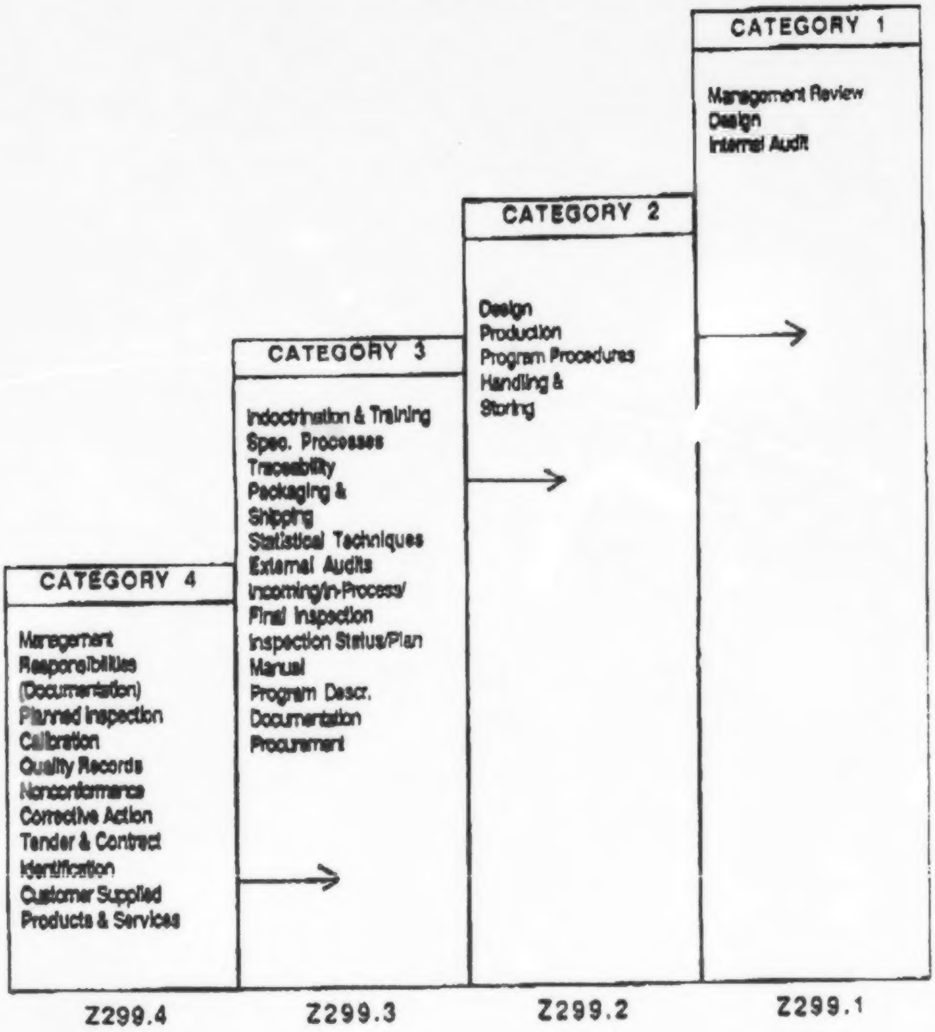
Let's look at the basic elements of these two standards and how they compare:

Chart 1 - Comparison Summary of CAN3-Z299/85 Categories, page 3 following.

Chart 2 - International Standards Comparison Chart, page 4 following.

CHART 1

COMPARISON SUMMARY
OF CAN3-Z299-1985
CATEGORIES


CATEGORY 1
Management Review
Design
Internal Audit
CATEGORY 2
Design
Production
Program Procedures
Handling &
Storing
CATEGORY 3
Indoctrination & Training
Spec. Processes
Traceability
Packaging &
Shipping
Statistical Techniques
External Audits
Incoming/In-Process/
Final Inspection
Inspection Status/Plan
Manual
Program Descr.
Documentation
Procurement
CATEGORY 4
Management
Responsibilities
(Documentation)
Planned Inspection
Calibration
Quality Records
Nonconformance
Corrective Action
Tender & Contract
Identification
Customer Supplied
Products & Services
Z299.4
Z299.3
Z299.2
Z299.1

©QUALITY MANAGEMENT INSTITUTE, 1987

CHART 2

ISO 9000	ISO 9001	ISO 9002	---------	ISO 9003
Z299.0	Z299.1	Z299.2	Z299.3	Z299.4
	BS5750 Part 1	BS5750 Part 2		BS5750 Part 3
	AQAP-1 (DND 1015)	AQAP-4 (DND 1016)		AQAP-9 (DND 1017)
	MIL-Q-9858A	MIL-1-45208		
ANSI/ASQC Q90	ANSI/ASQC Q91	ANSI/ASQC Q92		ANSI/ASQC Q93
	ASME Section 3		ASMESection: I: Power Boilers IV: Htg. Boilers VIII: Pressure Vessels NCA-3800	
	NCA 4000			
	ANSI/ASME NQA-1			
	10 CFR 50 App. B		SPEAR	
	N286		FORD CHRYSLER	
	NASANHB 5300 -4 (IB)		AAR M1003	

There is no short cut: implementing an effective quality assurance system is hard work. Like most worthwhile investments, it takes time and money. But, let's look at what some Canadian companies say about the payback!

ELECTROHOME - Supplier Management

(extracted from QMI Brief, Spring 1989)

Electrohome, Projection Systems, developed a Supply Line Improvement Program during 1988 to complement their quality assurance system (CAN3-Z299). This Program was developed by Materials Quality and Purchasing to reduce their supplier base, and develop the quality of that base more in keeping with their overall quality management strategy.

Key elements include: Identification of Critical Suppliers; Initial Supplier Contact; Supplier Survey; First-Off Approvals and Spec Review; and Feedback of Supplier Performance--Vendor Tracking System.

The Supply Line Improvement Program was officially launched with Electrohome, Projection Systems' suppliers in January, 1989. The program to date has had very positive results. There has been a reduction in non-conforming shipments by about 50%. At the same time, they have reduced their supplier base by 40%! (Guess which suppliers are gone.)

NATIONAL STEEL CAR: Cost Containment/Marketing Edge

National Steel Car designs and manufactures freight and railcars. One benefit of their quality program has been a dramatic 40% reduction in manhours spent dealing with the excess material, rework and inspections that results from not doing it right the first time. They also believe that they are looked upon more favourably in the marketplace because customers know that they'll get quality.

GOULD SHAWMUT: Marketing Edge

Gould Shawmut, makers of code and HRC fuses, have enjoyed increased market penetration and market share due to their demonstrated quality. They believe that demonstrated quality menas you enjoy more long-term contracts. When customers see you can deliver quality day-in, day-out, they'll go for a good stable relationship.

M. A. STEEL FOUNDRY: Cost Containment

M. A. Steel Foundry is one of the newest steel foundries in Canada and became the first foundry in Western Canada to register to CAN3-Z299.3/85. They believe that their customer satisfaction has improved and the amount of in-house rework has dropped significantly!

MICROTEL - Dual Registration - CAN3-Z299.2/85 and ISO 9002.

(extracted from QMI Brief, December 1988)

Microtel recognizes that competition in the telecommunications industry is always increasing, and that the best way to gain a competitive advantage is to continuously improve quality. They registered to CAN3-Z299.2/85 in December, 1987, and were the first company in North America to register to ISO 9002 and CAN3-Z299.2.

They state that inside Microtel, the Z299 standard has eliminated any argument about what to do with non-conforming materials, and helped to prevent many non-conformances altogether. Outside Microtel, the Z299 registration is an effective way of telling new and existing customers about their quality programs. In many cases, Microtel's customers now specify that their product should be built under a Z299 quality system, or the equivalent. Registration to Z299 put Microtel on the list of qualified suppliers right away! In accordance with Z299, quality requirements are routinely printed on Microtel's purchase orders, and the result has been fewer problems arising from confusion about what was bought. By adopting the ISO quality standard in addition to Z299.2, Microtel is well ahead in preparing for competition in the new global marketplace.

The stories are numerous, but the message is simple: With an effective, verifiable, quality assurance system, Canadian companies can survive, and indeed win, in the new global community!

SPEAKER : **JOHN COPELAND**

COMPANY : **MOBIL RESEARCH & DEVELOPMENT CORPORATION**

LOCATION : **ST. JOHN'S, NEWFOUNDLAND, CANADA**

TOPIC : **THE APPLICATION OF QUALITY ASSURANCE TO HIBERNIA: THE OPERATOR'S VIEWPOINT**

BIOGRAPHY:

John Copeland has an extensive background in engineering design, construction, operations and maintenance in the domestic and international refining and petrochemical industries. He has been involved in projects in Canada, the U.S.A., Japan, Singapore, Saudi Arabia, Italy and Indonesia.

Following 12 years with the Continental Oil Company, Mr. Copeland joined the Mobil Oil Corporation in 1972 and subsequently Mobil Research and Development Corporation (MRDC) where he has held several managerial positions in engineering and quality assurance for major international projects.

Presently he is a Senior Associate Engineer with MRDC and is the Quality Assurance Manager for the Hibernia Development Project based in St. John's, Newfoundland.

Mr. Copeland holds a B.S. degree in Geology from Centenary College of Louisiana and B.S. degree in Mechanical Engineering from Louisiana State University. He is a registered professional engineer in Texas and Louisiana.

Abstract

Design and construction projects for offshore production facilities have special quality assurance and quality control requirements. These requirements can be burdens to contractors and suppliers, especially those facing them for the first time. On the other hand, they can be guidelines to successful and profitable performance. This paper discusses some of the basic requirements of a successful quality assurance program, explores some of the myths surrounding quality assurance and offshore projects and sites examples of how "Q A pays".

Introduction

The fact that offshore projects require a level of quality assurance beyond that of most industrial projects has been interpreted as being a major contributor to project cost, schedule and quality problems - as if demanding a high degree of quality meant that the project could not be completed without an unusually high cost or a delayed schedule. Mobil contends that the opposite is true and that the contractor and supplier can make the quality assurance effort pay, not cost.

The purpose of this presentation is not to tell the contractor or the supplier how to write a Q A Manual or how to organize his company for the quality assurance effort. Nor is it to review in detail Mobil's specifications. Instead the presentation is intended to provide background information on quality assurance as it applies to offshore projects; to outline Mobil's expectations in terms of quality performance from its suppliers and contractors, and to reinforce the message that quality assurance is the key to the most profitable way of working in the offshore industry.

Five basic principles apply to quality assurance in general and to the offshore industry in particular. These are:

1. Quality Assurance in the offshore industry has evolved from the need for "traceability ".

2. Quality Assurance, at its simplest, means "conformance to project specifications".

3. Quality Assurance applies to all aspects of the work: engineering, procurement, fabrication and construction.

4. Quality Assurance is about "doing it right the first time", and...

5. "Quality Assurance pays".

Before discussing how quality assurance can be cost effective and how "doing it right the first time" is the economical way, the fastest way and the quality way to successfully undertake a contract or purchase order, it would be helpful to consider some basic definitions. The terms quality assurance (Q A) and quality control (Q C) are often used in the offshore industry but what do these terms mean and how are they applied?

- Quality Assurance is the process of ensuring that all aspects of the project work will be performed correctly and in conformance with the project specifications, while ...

- Quality Control is the measurement component of Quality Assurance, that is, the inspection and testing that verify that the work has been done to the given specifications.

Because of the hostile environment and the confined space for processing hydrocarbons, the structural integrity of the platform and the reliability of its systems for production, utility and life support are essential. The potential for catastrophic loss of personnel and materials requires that the historical construction record of the platform and any of its components can be retraced from engineering design through procurement, fabrication, construction, commissioning and production. Traceability means, for example, that installed materials and equipment can be followed back to their source, such as by using the mill reports for steel materials. Controlling the design, supply, fabrication, installation, and operation of each element becomes critical in ensuring traceability. This control is achieved through the project quality assurance process.

The Myths of Quality Assurance

Several myths surround the subject of Quality Assurance in its application to offshore projects. These myths have arisen from the complexity of the design and construction of production platforms, particularly in the North Sea. There, the efforts have been massive to perform the work and do it with the necessary quality consistent with the environmental, safety and technical criteria of the projects. Project budgets have been overrun and schedules have been delayed. As projects grew in complexity so did the quality assurance function and incorrect associations were made between poor project results and quality assurance requirements. Some of these myths include:

Myth 1. "Q A only applies to welding":

One of the myths of quality assurance is the one that says only welding is subject to extensive inspection and audit; only welding needs to have written and tested procedures; only welding and welders need to be certified.

Welding is certainly significant - in the Hibernia structure and topsides combined there will be about 20 000 tonnes of welded structural steel and about 5 000 tonnes of welded steel and alloy piping. Welding is significant but so is every other aspect from design to operations.

We have already stated that quality assurance and control is applicable to all aspects of the work, from design to operations. Thus, when we talk about quality assurance, we are talking about ensuring that all facets of the project are done correctly and in conformance with the project specifications.

As an example of the application of quality assurance in other areas, consider its use in engineering. Many of the major engineering companies involved in the design of offshore production facilities have established quality audit procedures. At key stages in the design, senior company engineers in the company's quality assurance group review the engineering details for conformance to company standards, the client's specifications and good industry practice.

Myth 2. "Q A costs time and money":

Whether the comment comes from the design engineer, the fabricator, or the construction contractor, you often hear the following: "We have our standard methods for performing and inspecting the work. There's no need for special work methods. They only cost time and money."

Consider the 5 000 tonnes of welded piping on the Hibernia project. This represents about 50 000 welds. A 10% defect rate, for example, would require an additional 5 000 repairs, cut-outs and rewelds and perhaps 50 000 hours of fitting, welding, inspection and supervision at a cost of say, $2.5 million - obviously an incentive for ensuring quality work and for doing it right the first time. Doesn't quality assurance pay?

Myth 3. "All you need is a Q A Manual":

It is sometimes implied that all that is needed to impress the client when it comes to quality assurance is a Q A Manual. Once the contractor has qualified with the client, and then successfully won the bid, the work effort can revert to standard contractor procedures. The mentality is "Let's spend a few dollars preparing a Q A Manual, show it to the client, and then let's get on with the work in our usual way."

It is true that without the appropriate quality assurance documentation a contractor will not pass the initial qualification stage, but it is courting disaster to think that once the work begins the contractor can ignore the quality assurance principles he presented to the client in his qualification document.

How many fabricators, for example, will read this paper and say to themselves: "We've got our Q A manual; paid good money to develop it, but we really don't need it. We're experienced in all these things - the specs, the reporting and documentation requirements, inspection by the certifying authority and client inspectors. We can handle it."

Others have said the same things before. We recall how one yard took on a major fabrication contract and began welding of the structural steel plate with a repair rate as high as 80%. Only after the yard realized that to meet the requirements of that particular contract it had to improve the quality of its welders, the extent of its internal inspection, and its conformance to the specifications for welding equipment and consumables, did it turn the project successfully around.

Myth 4. "Q A is a part time job":

Whether it's engineering or whether it's fabrication, often the contractor's response to the client's demand for a Q A program is to try to absorb the quality assurance effort into the normal work routine using the same personnel that perform and supervise the work. For example, in engineering, the design checks may be done to the contractor's normal standards rather than to the project specifications. In fabrication, the production department might use its foremen and inspectors to verify the work without scheduling quality audits at critical phases of the work. All of these standard checks are fine; but it is essential that contractors recognize that there are also special project requirements, that these must be communicated to the design office and to the production floor, and that the work is to be performed in accordance with these project standards.

One of the problems encountered by contractors especially those involved in offshore work for the first time is the failure to recognize that offshore projects do have these special requirements that necessitate special procedures and added measures of quality assurance. A classic example is the shipyard which leaves its traditional ship building role to fabricate offshore modules, decks or jackets. From its historical production and manufacturing techniques, the yard is thrust into a world of countless specifications, critical schedules, multi levels of inspection, extensive reporting, weight monitoring, documentation control, etc. The production manager must meet the demands of this project while managing other work on the production floor.

To put it simply, a company must be able to operate in the project mode while conductng its other, more traditional, work in the normal fashion without having the company torn apart by this diversification of work.

Another example will illustrate this point. On one offshore project the fabrication yard rarely involved its production manager in progress meetings with the client. He was required to carry out the fabrication for the project using the normal yard fabrication procedures, and was expected to turn out the other yard work at the same time. The production manager was relatively unfamiliar with offshore project specifications, possibly a little intimidated by these requirements, and resistant to changing his production methods. Ultimately, as the project schedule became seriously jeopardized, he had to be removed from the work. The yard established a project task force to undertake the offshore related fabrication. This, of course, caused other problems with an unhappy, and perhaps embarrassed, production manager but probably resulted in the best solution in unfortunate circumstances.

Companies and their personnel who don't recognize the special requirements of the offshore, and the full time requirements of quality assurance, are not likely to succeed.

Myth 5. "The client will run the project Q A program":

Mobil will specify the quality assurance requirements for the project, guide contractors and suppliers in developing adequate quality assurance programs, and monitor and audit the work to ensure a high standard of performance in accordance with the project specifications.

Mobil will not manage the contractor's Q A Program.

The contractor and supplier must decide how the work is going to be done, what resources are going to be applied and how the required quality is to be achieved.

The responsibility for recognizing and responding to the demands of offshore projects rests with the same managers who decided that the company would bid and perform the work. It is unfair, and likely unsuccessful, for these managers to then turn over the project to a lead engineer, or a production supervisor or a construction superintendent without advising him of the project's special technical and quality requirements, and without providing him with the special resources and facilities necessary to perform the work.

Part 4 of British Quality Assurance Standard 5750 makes the significant statement that "Quality is the responsibility of management. To attain the required quality, management has to specify its objectives, establish policies and a system of procedures to accomplish them, assign duties, delegate authority, set up adequate methods and standards of performance and evaluate results objectively."

It is important to realize that it is management's responsibility to ensure project quality - not the trades person, not the foreman, not the design engineer, not the scheduler, not the inspector. Of course, a team approach is necessary wherein everyone participates and cooperates, but quality assurance begins and ends with management.

Specifications: Technical and Quality

Consider the definition of quality assurance that has been given: "conformance to specifications". This means conformance not only to the project technical specifications but also to the specifications for the quality related functions of the project - the audits and inspections that verify that the work is indeed in conformance with the technical specifications.

It is useful to discuss these project specifications, both the technical criteria and the quality standards. These represent the "what" and the "how" of the project work.

1. Technical Specifications. Mobil has developed a series of technical specifications that govern design, selection of equipment and materials, construction and installation. These reflect good industry practice and the company's experience in similar projects.

These specifications also reference the relevant mandatory government regulations. In Canada, the Canadian Oil and Gas Lands Administration (COGLA) offshore regulations are in draft form and for Hibernia, Mobil will likely also specify equivalent international standards, subject to government approval.

Mobil's technical specifications also refer to various industrial codes and standards. These will be familiar to Canadian industry, particularly the energy industry, and include relevant standards from CSA, ANSI, API, AWS, ASME and other associations.

While individual specifications and standards may be familiar to contractors and suppliers, for offshore projects the specifications tend to be more detailed and voluminous, subject to more literal interpretation, and involve several levels of inspection to ensure compliance.

For example, on a recent offshore project, the specification for fabricating a structural steel skid on which equipment could be mounted, consisted of 30 pages. In addition, it cross referenced 12 industry codes and 6 other project specifications. Similarly, the requisition package for a gas turbine driven compressor included 29 project specifications, 8 data sheets and 6 drawings.

2. Quality Standards. As it does for the project technical specifications, Mobil also establishes the project quality standards. These are the criteria for monitoring the performance of the work to ensure conformance to the technical requirements.

The project quality standards include:

- Mobil's Q A Plan as a guide for contractors and suppliers in the quality performance of the work.

- national standards of quality assurance, such as those of the Canadian Standards Association. These serve as universal guidelines in developing quality assurance programs

- contractors' and suppliers' internal Q A programs. These include the general Q A Manual for managing normal work, and a project-specific Q A Plan.

Contractor's Q A Documentation

The contractor and supplier are expected to demonstrate and implement certain quality assurance documentation in order to qualify for, and perform, project work. The contractor's quality assurance documentation should include:

1. The Q A Manual. This contains the contractor's standard procedures which commit it to ensuring that the work will meet both the contractor's internal requirements and the client's specifications.

To be effective, the procedures in the Q A Manual must be:

- Practical: the contractor must be able to use the procedures; the manual is not merely for show and tell. Personnel in all departments must be able to apply the procedures as required.

- Definitive: the procedures must define the methods for conducting and auditing the work

- Correct: the procedures should conform to CSA Z299, or at least be adaptable to that level

- Current: the procedures will have to be constantly updated by assigned personnel

Each procedure should have the same simple, clear format consisting of the following sections:

- Purpose of the procedure

- Scope of work covered by the procedure

- Responsibilities for performing, managing and auditing the work

- Activity lists for those with defined responsibilities under the procedure

- Progress reporting forms to monitor the work

2. The Q A Plan. For most work, the contractor's Q A Manual is satisfactory; but for special work, such as the Hibernia project, a project-specific Q A Plan will need to be developed, probably by upgrading the standard Q A Manual to meet the project requirements. Therefore, the Q A Plan is simply a more detailed, more specific Q A Manual.

What is the best approach to preparing quality assurance documentation? For offshore projects, such as Hibernia, there are at least three relevant quality assurance standards which can be used as guidelines:

- Canadian Standards Association (CSA) Z299, Levels 1,2,3 and 4 which, respectively, deal with the requirements for quality assurance, quality control, quality verification and inspection

- Norwegian Standards (NS) 5801, 5802 and 5803 dealing with quality assurance and inspection
- British Standards (BS) 5750, Parts 1 (specifications for design, manufacture and installation), 2 (specifications for manufacture and installation) and 3 (specification for final inspection and test)

These quality standards are similar in many respects but CSA Z299 is referenced here as a guide to preparing a Quality Assurance Manual or Plan since this standard will likely be applied on Canada's Hibernia Project.

The Z299 standards decrease in severity from Level 1 to 4. To determine the level of quality assurance applicable to any project, the design, production and safety parameters of the project are assessed. For example, Level 1 requires a degree of quality assurance that:

- has an extensive design process
- prevents defects and identifies and corrects errors during the progress of the work
- results in extreme cost and safety risk if failure occurs

It can be assumed that the Hibernia project will require a level of quality assurance equal to CSA Z299, Level 1.

Note that the international quality assurance standards only serve as guidelines and are not comprehensive Q A Manuals in themselves. Nonetheless, they are constructive guidelines upon which a strong quality assurance program can be built. For example, British Standard 5750, Part 1, Specification for Design, Manufacture and Installation, says in reference to the requirements for a quality system: " The supplier (contractor) shall establish, document and maintain an effective and economical quality system to ensure and demonstrate that material or services conform to the specified requirements.The documented quality system shall include quality management objectives, policies, organization and procedures to demonstrate compliance with the requirements of this standard."

The different international quality standards all require that quality assurance documentation such as a Q A Manual or a Q A Plan present the following:

- general objectives of the quality program
- company organization, including the role of quality assurance in the corporate structure
- manual of quality assurance and quality control procedures
- work audit procedures
- special procedures

- control methods for manufacturing and fabrication processes
- planning and scheduling procedures
- work instructions
- design control
- change control
- inspection control: testing, in-process inspection, final inspection
- procurement control
- material control: preservation, packing, shipping, receiving, handling and storage
- control of free issue material
- identification and traceability processes
- documentation control and record keeping methods
- methods for identifying nonconformances and taking corrective action
- techniques for training personnel to carry out the work and the work audits

As an example of a work activity which is special to the offshore and which requires special technical and quality assurance procedures, consider "platform weight control". The platform is sensitive to topsides weight and the resultant centre of gravity. These impact the design of the supporting structure, the transportation, the mating and towing of the platform. Historically, as weight and dimensional details are received from suppliers and fabricators, the tendency is for the actual weights to increase over those predicted. For Hibernia, a weight control program will be implemented by Mobil. The topsides weight control will be monitored and controlled in accordance with an established project procedure. Regular reporting of the weight in a standard project format will be required from the contractors involved in engineering, procurement, fabrication, construction and installation.

To focus on another topic that should be covered in quality assurance procedures, consider "documentation control" and, in particular, its relationship to "traceability".

For each individual pipe weld the following records must be prepared, filed and made accessible on demand:

- mill reports for each of the two segments of pipe being joined
- records of the welding procedure, welding equipment and consumables used in the weld process
- record of the welder who performed the weld and his welding qualifications

- records of nondestructive tests including, as applicable: visual, radiographic, ultra sonic, magnetic particle, dye penetrant

- record of pre and post weld heat treating

- record of pressure testing

- correlation of the weld to the project drawings to identify where the weld is located on the platform

- correlation of the weld to the piping spool drawings and to the project specifications to identify the material and fabrication standards to which it was completed

In addition, consider the documentation involved in the following, fairly typical sequence of events for one pipe weld.

Assume radiographic examination is being used as the specified method of nondestructive testing. The given weld may require a number of radiographs to examine the total circumference of that weld. Suppose just one of the radiographs indicates a weld defect. The defect is repaired and the repair is re-radiographed. Assume the repair is also defective. The original weld now must be cut out, a new weld made, and once again nondestructively tested with all the accompanying documentation. A further, common complication could be that the welder making the repairs is not the original welder.

The sequence of events just described occurs with sufficient frequency on a project as large in scope as Hibernia that, in addition to the problems of welding quality, it creates serious documentation control problems. Imagine trying to trace the material and welding history of this one example weld during the project, or at the end of the project when final reviews are being conducted prior to issuing the certificate of fitness, or even several years later when the weld becomes suspect for some reason. Now extend this need for traceability to all the pipe and structural welds, then to the mechanical, electrical, instrumentation and other project work. The necessity for a substantial and efficient documentation control procedure becomes evident.

Inspection and Audit

To ensure that the work is, in fact, done in conformance with the project specifications, there are review processes, by both client and contractor, which consist of inspections, quality audits and certification. Again, these apply throughout the phases of engineering, procurement, fabrication and construction.

We can summarize the inspection effort as follows:

- contractor's internal control and inspection

- Mobil's inspection and audit, and

- third party inspection by a Certifying Authority

The certifying authority is an independent inspection agency approved by the government but selected and contracted by Mobil. The C A will inspect and verify the project design, materials and equipment, and construction. It is important to note that the audit work by the C A is done in accordance with the project specifications and the referenced government regulations and industry codes. The C A is not entitled to impose additional specifications on the contractors and suppliers.

The conclusion of the C A's work is the issuance of a certificate of fitness acknowledging that the platform is fit for production.

Summary

Mobil's Q A program is dedicated to "doing it right the first time". Apart from averting potential problems, Mobil derives little satisfaction in identifying unsatisfactory work by its contractors. Bad work requires rework and that delays the project and costs both the client and contractor money.

The Canadian, British and Norwegian quality assurance standards and Mobil's project Q A Plan are useful as guidelines but require considerable additional effort by the contractor and supplier to develop a meaningful and practical quality assurance document. That is, these standards outline what should be included in an adequate quality assurance program but do not provide the specific procedures required. That is left to the individual contactor and supplier. If you do not have an adequate Q A Manual and feel that developing proper quality assurance documentation will be difficult, we suggest that you assign a responsible in-house team to undertake the preparation of the documentation, solicit professional help, and discuss your needs with Mobil.

Mobil is saying to you, the potential project contractor and supplier:

> "There are special technical and quality requirements for an offshore project like Hibernia. Assess these project requirements. Decide if you can comply with the specifications and if you can deliver on time, within budget and with the required quality. If you decide to "go for it", then make a management commitment to Quality Assurance for you, your staff and your company."

Remember the five principles of quality assurance:

- Q A means that your work will be traceable throughout its entire process
- Q A means "conformance to project specifications"
- Q A applies to all aspects of the work: engineering, procurement, fabrication and construction
- Q A means "doing it right the first time" and doing it right the first time is the most economical way, the fastest way and the quality way of doing your work
- and above all, remember: " Q A pays!"

Acknowledgements

The authors would like to thank Mobil Oil Canada for its encouragement and permission in publishing this paper.

References

1. "Quality Assurance", Volume 4, Mobil Hibernia Development Project Industrial Opportunities, 1988.

2. Stebbing, L. "Quality Assurance", Ellis Horwood, 1986.

3. CAN3.Z299.1 to .4, Canadian Standards Association, 1985.

4. "Requirements For The Contractor's Quality Assurance", NS.5801, 5802, 5803, Norwegian Engineering Industries Standardisation Centre.

5. "Quality Systems", British Standards Institution, BS.5750, 1979 to 1981.

SPEAKER : **EINAR S. RYTTING**

COMPANY : **EB CONSULTANTS A/S**

LOCATION : **NORWAY**

TOPIC : **ASSESSMENT OF QUALITY MANAGEMENT SYSTEMS**

BIOGRAPHY: Einar Sverre Rytting is Vice President of Quality & Management at EB Consultants A/S. He has been the Chairman of the Norwegian Society for Quality. Before joining EB Consultants A/S, Mr. Rytting worked with the Norwegian Federation of Engineering Industries, where he was responsible for their training section. One of his principle areas was to support and assist members in their preparation for offshore activities.

ASSESSMENT OF QUALITY MANAGEMENT SYSTEMS

During the 70's there were certain events that forced the Authorities to review its control strategy.

On one side we had some serious accidents in the North Sea causing human loses and environmental damage. On the other side there were projects with huge overruns on cost. This was the background to the Norwegian Authorities when they started the work developing a new control philosophy.

A control philosophy based on internal control/quality assurance was chosen for the following reasons:

* Research and practical experience has shown that on complex units/projects such an offshore installation, safety had to be buildt into the project. It could not be ensured by the use of final inspection.

* With a system based on an internal control philosophy, the Authorities did not only focus on the platform safety, they also had to focus on the commercial side of the platform development. The project management and the cost control was in focus.
  (80 - 90% of the project cost are paid by the Authorities, through direct ownership and indirect through the tax system.

* Internal control was also a more cost efficient way of performing the control, both for the Authorities, operators and contractors/suppliers.

The overall objective was in a cost efficient way to ensure both the safety and the economic side of the platform development.

In 1981 the Authorities issued "The guidelines concerning the licencee's internal control in petroleum activities". At the same time the operators and the industry were preparing the Norwegian quality assurance standards NS 5801, NS 5802 and NS 5803. These standards were issued in 1981. The Norwegian standards are based on similar other national standards (such as the Canadian) and the MIL - Q 9858 from 1963.

The first Norwegian project to fully implement internal control/quality assurance as the control strategy, was the GULLFAKS A project, which started in 1981.

When the Gullfaks A project started there were consenses between Authorities, operators and the industry about the chosen control strategy. But in the practical implementation of it, they had still a long way to go.

This paper will present some of the gained experience from the Gullfaks A, B and C projects up to 1989, focusing on the development in this period.

Before starting the major chapter, I have the following remark.

"The development of this type of systems/strategies have two phases. In the start one see all the disadvantages of the old system (inspection) and all advantages of the new system (quality assurance). After some years of practice with the new system (quality assurance), one see all the dissadvantages of the new system. All the disadvantages of the old systems (inspection) has been forgotten".

THE OPERATOR

The success or failure of a project will always be the responsibility of the operator and his management.

The operator will set the objectives and develop the strategies which he feel is best suited to ensure the success of the project.

For this type of projects the objectives will be related to safety (Personnel/Environment), cost and schedule.

The set of objectives will be reflected in the work through:

- Platform consept
- Overall project strategy
- Contract strategy
- Control strategy.

This development will be a dynamic process effected by the technological and the political development. Examples can be the development in crane capasity and the following development towards larger modules - the Troll platform, weight 40 - 45000 metric tons will have 5 large modules, compared with 17 on the Gullfaks project in the early 80th's. Another element could be requirements related to the local content of the deliveries.

Our experience is that the most natural timing for operators' presentation of his project organization to delivery industry will be in the early pre-engineering/consept engineering phase.

The operator and his management team will as part of the project-preparation develop the control strategy for the project. If quality assurance is selected, our experience from previous North Sea Projects have shown the following:

- An offshore platform will to a large extent be a prototype. If we look on the platform in more detail, we will see that it consist of

  20 - 25 Contracts (Contractors)
  200 - 300 Purchase Orders (Suppliers)
  and a large number of subcontractors and subsuppliers.

From a "Quality Assurance" point of view, these Contracts and Purchase orders can further be split into two groups:

- "Prototype" - deliveries
- "Standard products" - deliveries.

Why focusing on this aspect?
Because on projects as the Hibernia project and other large North Sea developments, one need to focus on other areas/activities than those traditionally connected with Quality Assurance.

Our experience shows that most of the problems were related to "prototype" deliveries. Problem areas were:

- Organization
- Planning
- Engineering
- Contract
- Non Conformance/Corrective Actions.

Another experience is that companies familiar with Quality Assurance, but new to the offshore market and it's requirements, had problems within the area of Quality Assurance. This observation surprised us, and was therefore analysed in more detail.

One observation could be drawn:

- The companies familiar with Quality Assurance requirements, were mainly the ones engaged in serial production like defence production or partsdeliveries to automotive production. The focus was towards production, and not in the areas that causes problems in offshore deliveries.

* Companies which had defence contracts and delivered "prototypes", did not have the same pressure towards cost and schedule as they would have had in similar offshore contracts. This shows that the QA function has not put priority on organization and planning.

Personnel with traditional quality assurance background, required retraining in order to work on offshore projects. Many was not able to meet the new requirements and resigned their job in the project.

Another cathegory of people was needed. Personel from general management, planning, engineering, EDP and business, was recruited into the Quality Assurance function.

The operator must be able to communicate his needs and experience to the industry. He cannot expect that the local industry have the full understanding of his problems. Even if these activities in short range means extra cost, it will repay during the project. Competition will be stronger in the industry, and there will be less problems related to contractors/supplier who do not meet the operator's requirements.

The contractors and suppliers will fully understand the operators needs. The operator will then also have an industry doing things right the first time and working efficient to meet the established objectives. The effect on cost will be positive and there should be few problems meeting schedule.

COOPERATION BETWEEN OPERATOR AND THE INDUSTRY

As already mentioned the success of a project depends mainly on the operator and his management. Other parties such as investors and the authorities will also be conserned with the success of the project.

The "Success factors" are different for the different parties:

INVESTORS - COMMERCIAL SIDE
- SAFETY

AUTHORITIES - COMMERCIAL SIDE
- BENEFIT TO LOCAL INDUSTRY
- NEW JOBS LOCALLY
- SAFETY.

As mentioned in the previous chapter a good relationship between the operator and the industry will be of mutual benefit to all parties. This was the reason behind "The Gullfaks" Seminars". One had also observed that knowing the operator and the way he conducted his business, gave a major advantage in obtaining contracts. The operator created a larger and more competitive market.

Therefore in connection with the development of the Gullfaks field, starting in 1981, a serie of seminars was developed. ("The Gullfaks Seminars"). This was done as a joint effort between the operator and the Norwegian Federation of Engineering Industries.

There were two types of seminars:

- * The upper management seminar

- * Professional seminar within the areas of:

  - Organization of work
    - Technical specification
    - Organization and project control
    - Personnel management
    - Material/documentation.

  - Quality Assurance
  - Contract administration
  - Preparation of Tender Documents.

Four documents were issued covering the subjects presented in the seminars.

Only within the area of quality assurance, the operator and the Norwegian Fedration of Engineering Industries arranged locally 30 seminars, in addition to the main ones.

Based on the good experience on Gullfaks, similar seminars have been arranged in connection with the Oseberg, Snorre and Sleipner projects. But in minor dimentions in the latest projects.

CONSENSUS

Before going into detail on how to establish consensus within the project organization, I will say something about the life and nature of this type of organization.

A project organization, like the one for the Hibernia-development, will consist of people with different background and experience. An importance task for the operator will be to make sure that the project organization will function as a team as soon as possible.

The personnel shall understand and practise the chosen objectives and strategy for the project, and proper communications lines both formal and informal should be established.

A complicating factor is the projects' many phases. People are mobilized and demobilized. Only a limited number of the people follow the project from start to end.

In 1981, the management on the Gullfaks project, selected the "Team Building" consept as a tool to develop the following:

- Consensus
    - Objectives
    - Project Strategy.
- Communication
    - Formal
    - Informal.
- Team spirit/Involvement.

When starting in 1981, there were a certain amount of scepticism. Today Team Building activities is a natural part of the project activities for the Norwegian operators.

IN WHICH WAY ARE TEAMBUILDING ACTIVITIES ORGANIZED?

Step 1 Teambuilding sessions on disciplin/group level.

Topics Overall Objectives Project
Strategy (Contract, Quality Assurance planning)
Topics directly related to discipline or
group, effected by the selected Objective and
Strategy.

Step 2 Teambuilding session; groups with interfaces, where good understanding/communciation are of great importance to ensure the success of the project.

Topics direct related to the groups participating
Topics related to interface improvement.

Step 1 is to start with the groups according to the organization chart (such as mechanical engineering, process, electrical, contract, planning etc.). In Step 2 one bring together groups with strong interface. Interfaces that, if they do not function satisfactory, can effect the safety, cost or schedule of the project.

A typical teambuilding seminar will start after lunch, with 5 to 6 hours on selected topics. The day finished with dinner and thereafter it will be time for more informal meetings and discussions.

WHAT HAVE THIS TO DO WITH QUALITY ASSESSMENTS ?

"Team Building" activities will also have Quality Assurance as a central topic. It will be an important tool to ensure the quality of the project-organization like:

Operator	-	His main benefit will be in creating a good internal communication. Lack of communication is an important source for quality problems, (on this type of project).
Industry	-	The industry will have an operator that is talking with one voice. It should not matter if he talked to the project director, engineering or QA manager or disciplin engineer.

QUALITY ASSURANCE LEVELS

When quality assurance requirements have been defined in contracts or purchase orders, different levels of quality assurance requirements (ISO 9001, 9002 or 9003) could be selected, based on an evaluation of risks and complexibility. Different projects have handled this selection process in different ways.

On one of the larger Norwegian projects one worried about that there could be a tendency of selecting a higher quality assurance level than needed. This could increase the price on the contract or purchasing order. It would also effect the projects cost related to surveying and monitoring.

The selection process both on other projects and of other operators, were also analysed. The following observations were made:

- On previous projects there had been a tendency of safeguarding one-self by selecting higher QA-level than needed. "If you select a high quality assurance level you do not do anything wrong".
- Due to the fact that the responsible engineer often felt that he lacked knowledge on quality assurance matter, the selection process was in the hands of the quality assurance function, which did not always have knowledge of the complexity, and risk related to "scope of work".

- The later planning of the quality assessments activities was to a large extent based on the selected QA-level.

- Some operators had systems where one was asked to review a number of criteries giving score from 3 (high) to 1 (low) or 0 (not applicable). From than on it was just plane mathematics, the individual score was summed up, if the result was between 0 - 10 it would mean selecting ISO 9003, 10 - 20 would mean selecting ISO 9002 and 20 - 30 ment selecting ISO 9001.

  This system had some weaknesses that could not be accepted, because by making the selection process into a mathematical excercise, one deprived the responsibility from management.

  One also experienced that a mathematical excercise could lead to an incorrect conclusion. Even with a score of 8 it could be correct to select ISO 9001. Special matters related to one criteria would be enough.

The following points were built into the system for "Selection of Quality Assurance Requirement".

> Structure
> Simplicity
> Use of common sense.

A document containing an evaluation part and a conclusion part was developed.

Example
EVALUATION OF"SCE OF WORK"

		HIGH	MED.	LOW	NOT APPL.
RISK	- Safety - Economical Values - Critical Milestones				
IMPORTANCE	- Value (Price) - Basis for significant - Schedule				
COMPLEXITY	- Technical - Management/Control - New Design.				

CONCLUSION:

Based upon the above evaluation and my general experience with this type of equipment/work, the QA-requirement is stated as:

This new system was tested by selecting purchase orders from previous projects. The test groups (dessions makers on the project) were asked to go through the evaluation form and determine the quality assurance level to be used.

Result.

- On average the selected QA level was one level lower than on previous project.
- There were very little variance between the test group answer.
- Time used per contract/purchase order where 5 - 15 minutes per evaluation.

Systems based on these principles are today in use on Norwegian offshore projects. It have clearly increased the efficiency of the QA-function.

QUALITY ASSESSMENT

There has been an increasied understanding and commitment for quality assurance and quality assessment by many companies over the last few years.
It began with the demand by NATO for quality assured products and the subsequent assessment of companies to the Allied Quality Assurance Publications (AQAP), and to military standards and spec's.

Based on the need for safe and reliable products in the offshore and oil industries one has discovered an increased interest for quality management and the subsequent quality assessment/system audits. The managers and leaders of many companies have realized that quality assurance also is effective management, and that system audits are closing the control loop at the management level.

The quality assessment should be looked at as two main activites, which is the assessment and the internal audits.

The projects on the Norwegian Continental Shelf had all a number of audit teams visiting contractors and subsuppliers to evaluate their management systems and organization.

These audit teams have issued a considerable number of corrective action-requests and recommendations to company managers.

When the project organization started the assessment of suppliers, they began with the prequalification of the bidders. This was achieved by reviewing their superior documentation, usually their quality assurance handbook. The next step were implementation reviews of short listed bidders by interviewing managing directors or other managers in their companies.

The post contract activity used to be regular system audits, engineering technical audits and quality surveillance.

The assessments, or audits, used to be combined system and technical audits. The audit teams consisted of two to four persons. The team leader was a qualified system auditor. As a part of the team there were selected specialists according to the audit scope. Audit teams with only quality assurance personel were not accepted by the project management.

Each audit had to be professionally planned, prepared, carried out and reported.

THE CONTRACTORS/VENDORS

Implementation

Two common errors have been experienced when companies implement a quality assurance system:

- Overdocumentation
- "Formal" systems not reflecting real life.

This chapter will focus on these two items. There are also other area one should have in mind, such as training/team building. Some of the topics that I have related to the operator in this presentation, do also apply to contractors and suppliers.

When I talk about documentation in this presentation it will be related to the description of the systems and processes within the company, not the documentation which is part of the work, (certificates, drawings, test reports etc.)

Before going into details, I will give a short description of what often happen when a company find out that they need a QA-manual based on, say ISO 9001, to be on the bidders list.

The management do seldom have any understanding of quality assurance. But they do understand that they need a QA manual to be on the bidders list.

The next step will be to engage a consultant than can prepare the requested manual. What happen is that the consultant prepare a manual that meet the requirements of the selected standard. To be on the "safe" side, every requirement of standard are included. Also those which are not applicable neither for the "work" or the business.

This could be compared with a situation when someone is asked to prepare a map of St. John's showing the main roads. When he has finished he will present to you a detail map showing the smallest roads, house and trees, not of St. John's, but of Toronto.

If the QA manual is ready on time and accepted by the project, the company will be happy and satisfied with themself. But it is this approach that are the roots of all the problems related to "overdocumentation" and that "formal" systems do not reflecting the real life.

This story happens again and again even if warned by the operator.

How to create "Overdocumentation" and "Formal" systems:

= Describe every system and process within the comany, down to smallest sub-system in every detail, also those with no relevance to the "work" within the company.

= In describing the quality assurance system start from the quality assurance standard and make sure that every requirements are met in your QA manual, also if not applicable.

= When the description of systems are checked it should be towards the requirements of the standard, not the real life in the company.

This will create a negative attitude towards quality assurance and the work among the employees on all levels.

They will associate quality assurance with:

* Bureaucracy

* Waste (activities not adding value to work or product)

Some managers and specialists believe that if they want a high level of quality assurance, they only need to collect data and prepare documents, nothing could be more wrong. In their assessment of the quality assurance system they are more concerned with the documentation than the actual operations.

Guidance

The success of quality assurance means its ability to contribute to the success of the company of project.

In attacking the problems of established objectives and setting priorities, we have successfully used the "Critical success factors (CSF) method". The method was developed by a research team at MIT's Sloan School of Management in the late 70ths.

The method was originally used in connection with development of information systems, but our experience is that this consept can be used successfully both in implementing quality assurance and in the assessments of quality assurance systems.

The Objectives or Goals represent the end points that an organization, project or departments hopes to reach. The "Critical Success Factors" are the areas in which good performance is necessary to ensure attainment of those goals/ objectives.

In most organisation there are usually three to six factors that determine success. These key activities must be done exceedingly well for a project to sucessful. The "Critical Success Factors" thus are, for any project, the limited numbers of areas in which results, if they are satisfactory, will ensure successful performance for the project.

By using this method one is able to put priority on the important areas and the problems. "Overdocumenting" could be avoided.

The "Critial Sucess Factors" method have been used successfully in connection with quality assessment. "CSF" help the audit team to focus on the areas of importance to the project.

The understanding of the quality assurance function with management will increase when they consentrate on the important aspects of the project or busines.

When one start to develop the procedures, one should describe the real life.

The next step will be to check against the requirements of the contract or standard. Based on this evaluation one should determine if any processes or systems need to be upgraded.

When documentation is being made, always keep in mind that documentation is only a tool, it is not the object.

The requirements to documentation is not static within a project. It can vary from one unit to another. Example on elements effecting requirements related to levels of details in the documentation, can be the turnover of personnel within the organization.

Subjects of no relevance to the work or the activities within a project or company, should be left out.

Training/team building will always be an important factor when implementing quality assurance both for operators, contractors and vendors.

Rewards

Contractors and Vendors that have implemented a quality assurance system without falling into some of the pitfalls described earlier, would benefit from the quality assurance activities, also after the delivery to the project.

Quality assurance in connection with project focuses on the processes and systems within an organization. For those companies that have been successful in implementing quality assurance, it could mean the start of a permanent search for excellence, making the company more powerful in the market.

Another positive experience can be achieved by making the results visible in the organization. One important area could be if the quality assurance could be identified positively in the profit and loss account. The challenge in most projects and companies will be to find a practical way of doing it. I do not believe in complicated quality cost system, where the system cost end up higher than the benefits.

SPEAKER : KJETIL M. STULAND

COMPANY : NO-HA ENGINEERING A/S

LOCATION : NORWAY

TOPIC : A MAINTENANCE SYSTEM DESIGNED FOR LOW COST OPERATIONS

BIOGRAPHY:

Mr. Stuland has an M.Sc and PH.D. from the Norwegian Institute of Technology (1977).

Since 1980 working for the oil and gas industry in staff position wiht oil company, cunsultancy and manufacturing companies.

Mr. Stuland has worked on the following assignments: conceptual evaluations of oil and gas field developments; head of safety for an offshore field development project; evaluating all international oil and gas companies (20 in total) investments in offshore technology in Norway, advising government on alternative stragegies; advising the norwegian government on the global structure of oil and gas consulting, optional strategies to internationalize norwegian companies.

Since 1987 Managing Director of No-Ha Engineering A/S, a company supplying the offshore industry with fire fighting systems.

1. THE ABSTRACT.

The challange of offshore projects and operation made a significant shift in the spring of 1986. Since 1979, or even 1973 focuse was on production regularity as the margins were substential.

To design and operate an offshore field is under current conditions a matter of balancing income against cost. A large portion (typical 20-30 %) of the operational expences are related to maintenance, inspection and services. This paper is an outline on how to organize maintenance when effective maintenance is function of:

- A proven technology i.e. from both a maintenance and operational point of view.
- A maintenance strategy is adopted for the purpose of eliminate "unnecessary" maintenance, and to optimize time between each overhall.
- A maintenance system which provide adequate informations both on spare parts and technical legends.
- A multidiscipline maintenance organization utilizing both operator/production personell and maintenance personell for maintenance purposes.

2. THE CHALLENGE.

In the years of high profit margins, field operations were basically related to meet proposed production curve. Management as well as technical and organizational resources was utilized to enhance production - only.

As a simplifaction - the established "truth" was felt to be:

Profit $\sim$ production x price.

From outside corporate boardrooms it looked as if strategic thinking was guided by:

average long term profit $\sim$ (production of exploited fields + production from explored fields) x price of oil.

Leading to the thinking that the long term success of the company remained with oil field reserves at hand.

Current thinking is more of that "back to basic":

Profit = production x price - cost.

The cost element for upstream offshore field operations as for any traditional industrial investment, consists of two elements:

Total cost = Cost of investment + cost of operation.

A substantial element of the "cost of operation" is related to the maintenance.

3. THE PHILOSOFY.

The basic philosofy is to ensure low cost maintenance. This has been interpretated as:

*1. - "Optimal choises" of preventive and corrective maintenance, modifications and inspections.

*2. - "Optimal choises" of split between on and offshore works.

*3. - Identification of critical items and systems for operation and safety.

*4. - Define critical planning periods and split of responsibilities between the offshore and the onshore organization.

*5. - Specify a Maintenance System which at the same time interfaces between maintenance, materials, production, document, drilling and planning systems.

*6. - Organize own workforce and contractor workforce in an optimal way.

*7. - Make both technology/systems flexible but still standardize.

The main philopsophy is summarized as:

> "to reduce maintenance by optimizing the sequence of overhalls".

This is achieved by a continous evaluation of maintenance schedules on systems level. The adjustment of sequences is based on the systems conditions.

A fulfilled description of each of these elements of the philosophy are in themselves a subject for many papers. However, to establish a system it is necessary to bring ideal philosophy down to a workable strategy.

4. THE OBJECTIVES AND STATEGY.

Objectives in maintenance as anywhere else, must be measureable. To do this it is more practical to establish criterias of objectives as a subset to objectives themselves. In relation to established philosofy, the criterias are:

*1. - Modifications is to be coordinated and planned onshore at last three months ahead.

*2. - Cost estimates for on/offshore maintenance must be possible to be calculated both on- and offshore.

- On- and offshore maintenance must be brought into planning.

*3. - MPS must be structured with an ABC category stock control, both at own warehouse and at subsuppliers.

- All equipments are grouped in adeqate systems/groups purposely from a maintenance point of view.

- A tagging system working top - down, utilizing systems as the main tag to identify component.

- Integrated materials list and maintenance register, using tag number/part number as an identity. This is also required by subsuppliers/contractors.

*4. - Categorize systems and critical components for maintenance based on:

  - * fixed intervalls,
  - * evaluated intervalls,
  - * repair on failure.

- Multidiscipline maintenance teams using both production/operator personell and maintenance technicians for maintenance tasks.

- Planning on quarterly basis takes place onshore. Within each quarter planning is done offshore.

- Planning of major repairs/exchanges are done onshore.

- For systems which require special attentions (like BOP and RISERS, Concrete Base) it shall be possible to create separate maintenance modules, which interface the maintenance system.

*5. - The system shall be fully electronic in all aspects of:

  - planning,
  - workorder initiating,
  - approvals,
  - material requisition,
  - document control,
  - inspection/programme,
  - PM - programme.

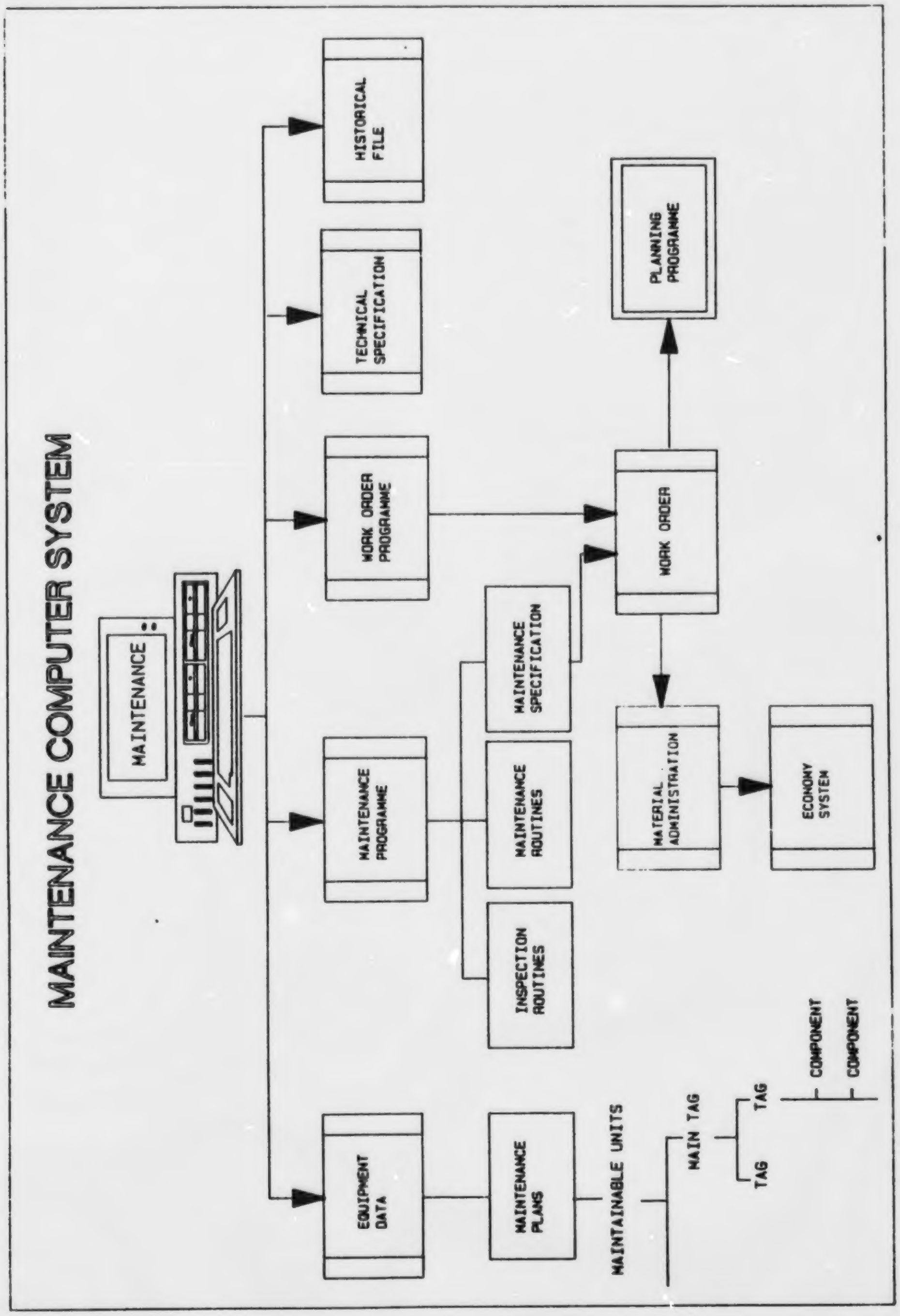
- A maintenance operation shall be able to controll and supervise from all above identified areas.

*6. - The organization of the system shall be so that it works in 'a close to real time' function, both for on- and offshore personnel, of both the oil company or any contractor with general maintenance agreements.

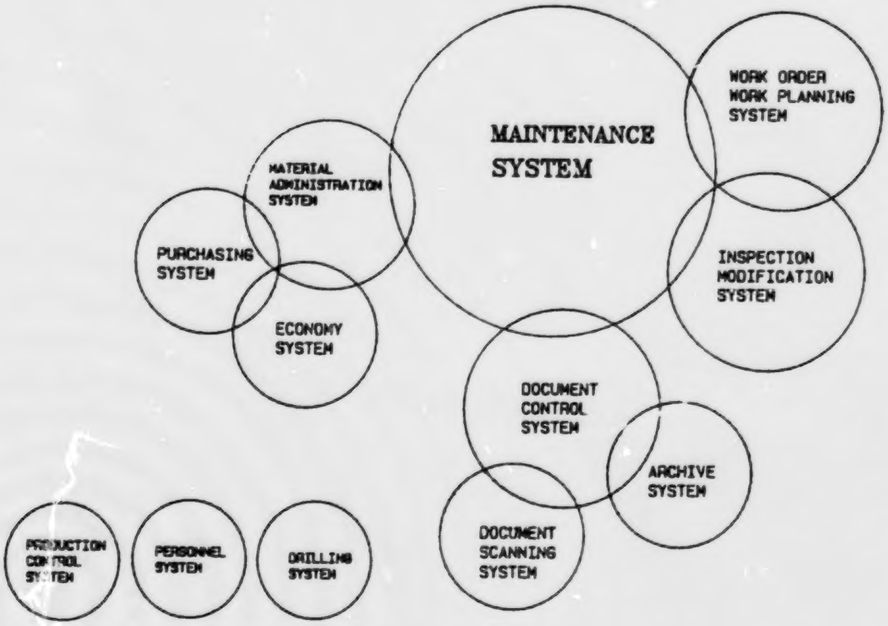
- Historically it shall be possible to control past performance of all systems, cost of maintenance work/spare parts etc.

5. THE SYSTEM.

In a schematic way the system meeting above mentioned philosofy and strategy looks like:


MAINTENANCE COMPUTER SYSTEM
MAINTENANCE
HISTORICAL FILE
TECHNICAL SPECIFICATION
WORK ORDER PROGRAMME
MAINTENANCE PROGRAMME
EQUIPMENT DATA
PLANNING PROGRAMME
WORK ORDER
MAINTENANCE SPECIFICATION
MAINTENANCE ROUTINES
INSPECTION ROUTINES
MATERIAL ADMINISTRATION
ECONOMY SYSTEM
MAINTENANCE PLANS
MAINTAINABLE UNITS
MAIN TAG
TAG
TAG
COMPONENT
COMPONENT

Where interfacing to other systems is shown schematical below:


MAINTENANCE SYSTEM
WORK ORDER WORK PLANNING SYSTEM
MATERIAL ADMINISTRATION SYSTEM
PURCHASING SYSTEM
ECONOMY SYSTEM
INSPECTION MODIFICATION SYSTEM
DOCUMENT CONTROL SYSTEM
ARCHIVE SYSTEM
DOCUMENT SCANNING SYSTEM
PRODUCTION CONTROL SYSTEM
PERSONNEL SYSTEM
DRILLING SYSTEM

6. THE ORGANIZATION.

A key element to achieve cost cut for maintenance is to improve productivity.

To achieve this it has been decided to:

- Allocate maintenance responsibility for each system only to 'one' function.
- Equipment that is not an area of qualified competence of the system responsible function, is maintained by specialists, under the responsibility of the system responsible function.
- This means that depending on the systems, the instrument and electrical specialist are responsible to the mechanical responsible function, and vice versa, i.e. doing maintenance as a team.
- Contractors can both be in position of taking systems responsibility or operate on behalf or under supervision of system responsible person.
- Inspection is physical inspection of main structure, pressure vessels, safety valves as specified by NPD, not periodical control of system which is the responsibility of maintenance.
- Safety, finance, document control, procurement, contracting, are all a responsibility of the maintenance function.

7. EXAMPLES.

As an example we take a fire water system consisting of:

- diesel engine,
- fire water pump (with jockey)
- fire water riser and main ring,
- deluge/sprinler skids,
- distribution piping.
- nozzles, hosereels, monitors.

On a general basis this system is 90 % mechanical, 5 % instrumentation, 5 % electrical i.e.

- Mechanical maintenance has system responsibility.

- Any maintenance on the system is carried out under planning and operational supervison of the mechanical maintenance.

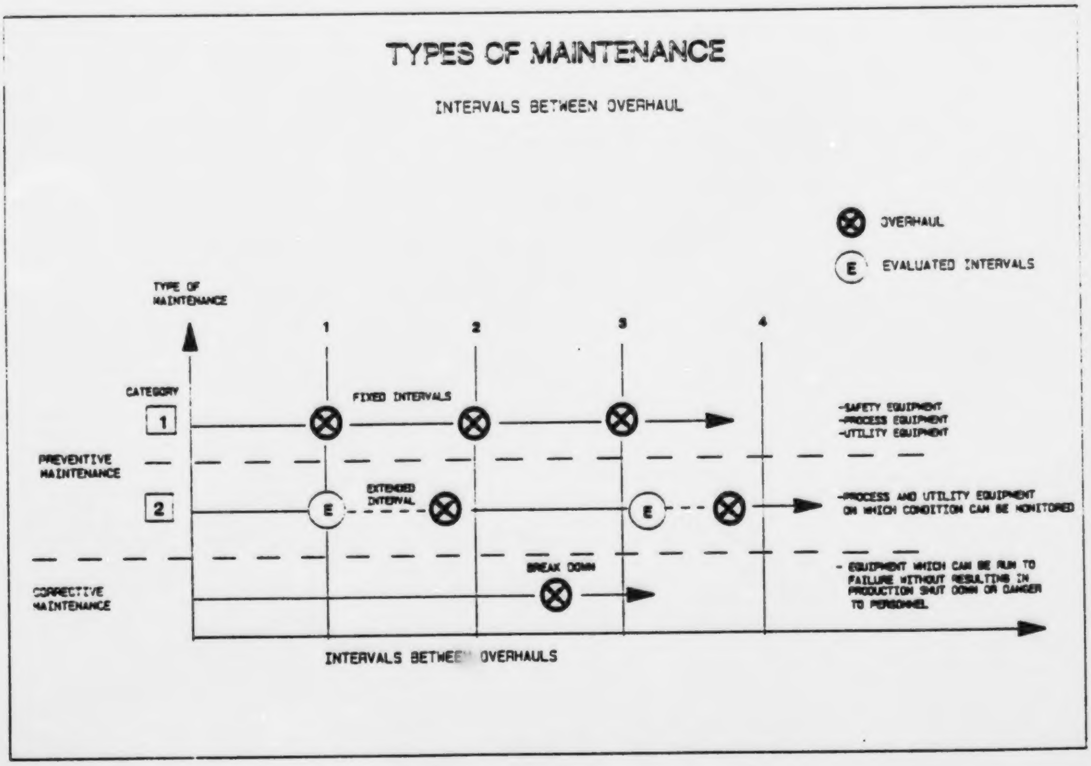
- Budget/financial accounts (AFE) are allocated to system, not on components or maintenance disciplines.

- The main tag is fire water system or fire water skid, equipment all from engine to hosereel become equipment tagged in relation to main tag.

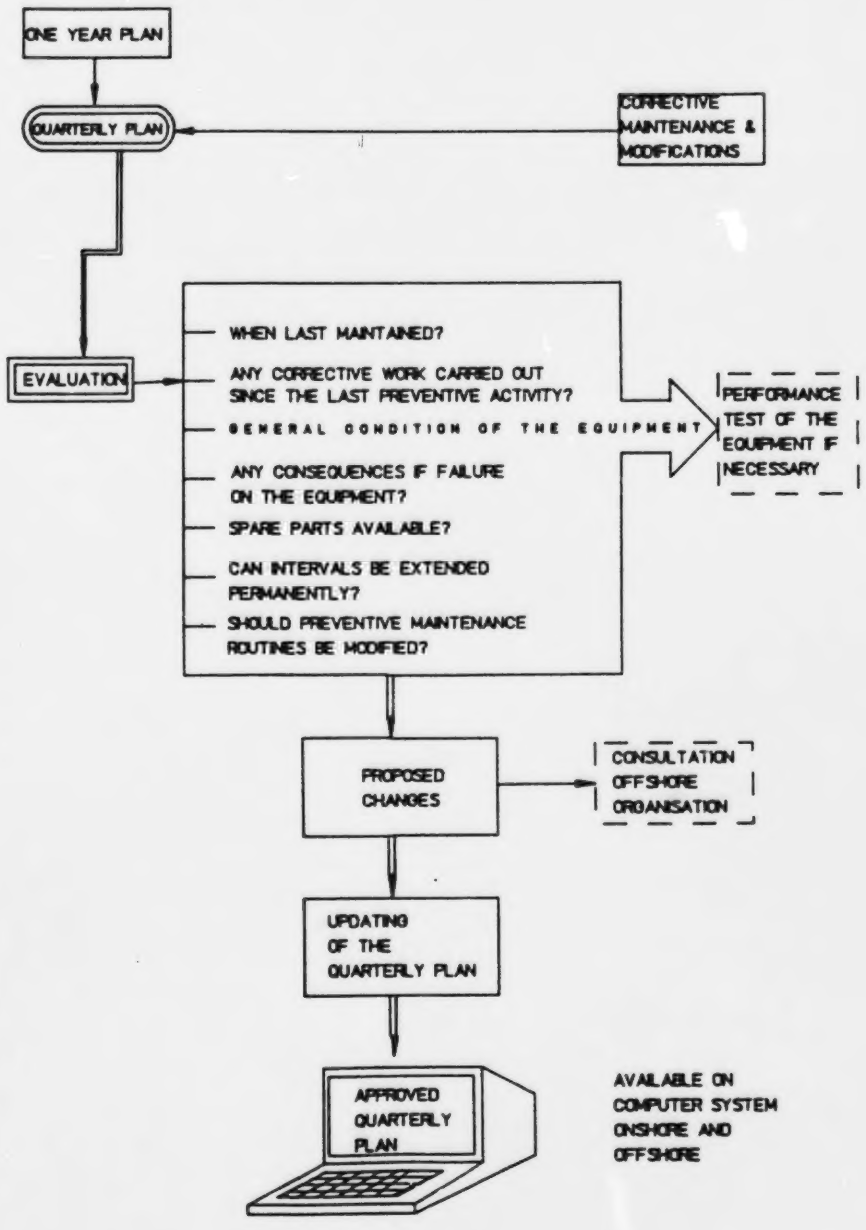
- As the system is a safety system periodic maintenance program (maintenance according to calendar) is done.

- Critical components are kept on stock at warehouse of either oil company or at subsuppliers, category A.

The planning is structured as outlined below:

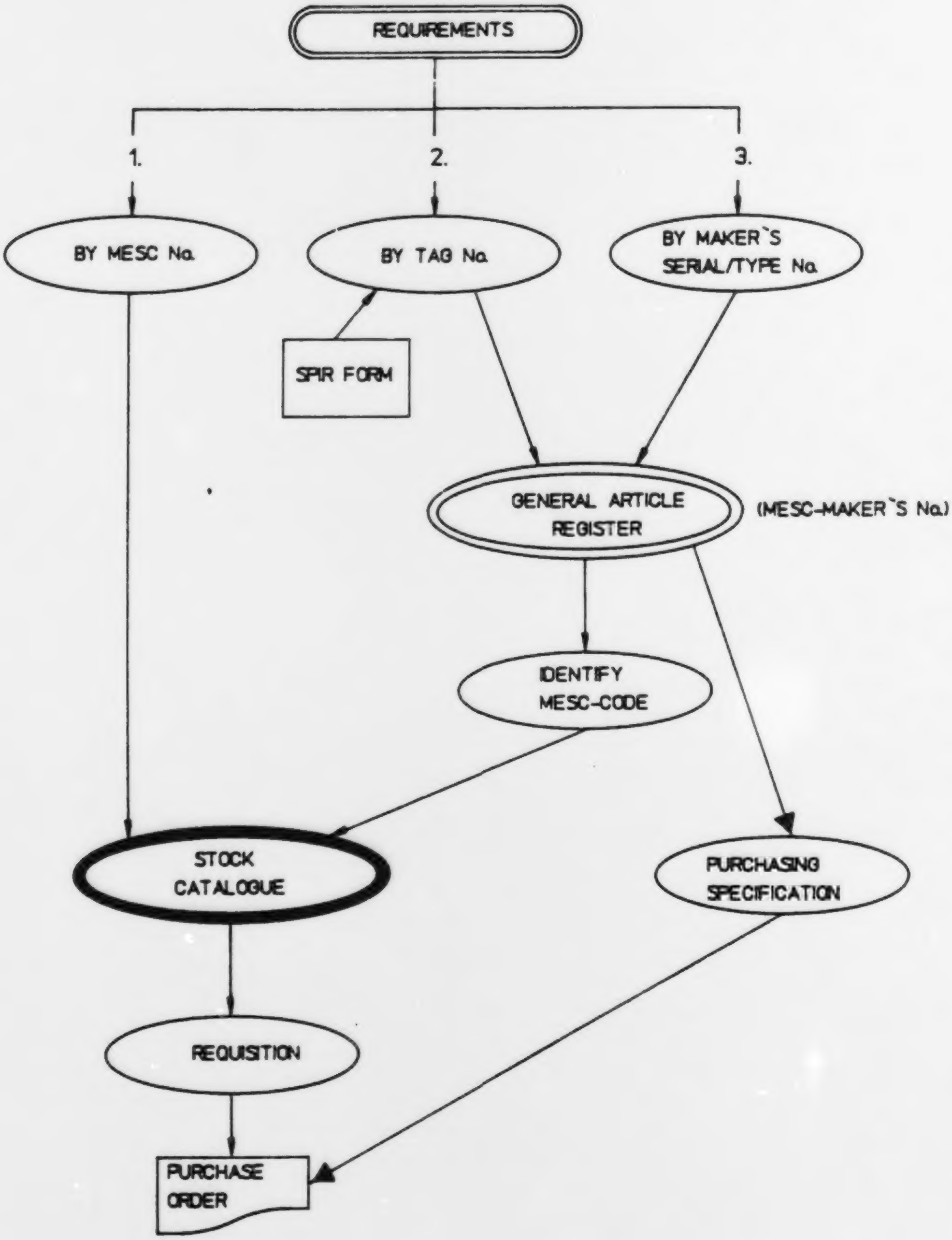

TYPES OF MAINTENANCE
INTERVALS BETWEEN OVERHAUL
OVERHAUL
E
EVALUATED INTERVALS
TYPE OF MAINTENANCE
1
2
3
4
CATEGORY
FIXED INTERVALS
1
-SAFETY EQUIPMENT
-PROCESS EQUIPMENT
-UTILITY EQUIPMENT
PREVENTIVE MAINTENANCE
2
E
EXTENDED INTERVAL
E
-PROCESS AND UTILITY EQUIPMENT ON WHICH CONDITION CAN BE MONITORED
BREAK DOWN
CORRECTIVE MAINTENANCE
- EQUIPMENT WHICH CAN BE RUN TO FAILURE WITHOUT RESULTING IN PRODUCTION SHUT DOWN OR DANGER TO PERSONNEL
INTERVALS BETWEEN OVERHAULS

EVALUATION - QUARTERLY (3 MONTH PLAN)

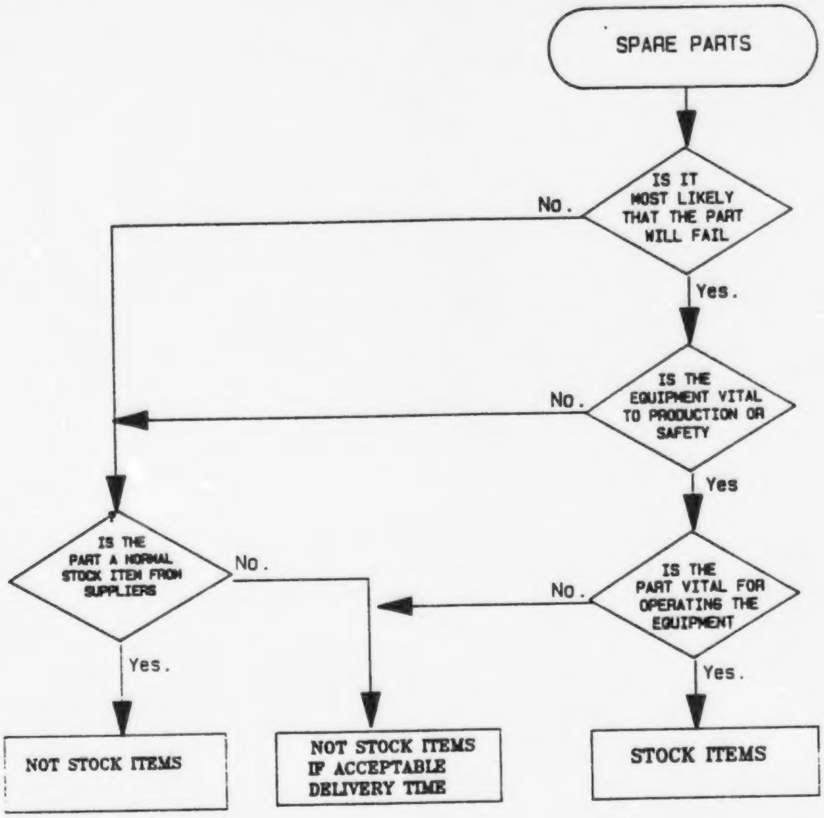

ONE YEAR PLAN
QUARTERLY PLAN
CORRECTIVE MAINTENANCE & MODIFICATIONS
EVALUATION
WHEN LAST MAINTAINED?
ANY CORRECTIVE WORK CARRIED OUT SINCE THE LAST PREVENTIVE ACTIVITY?
GENERAL CONDITION OF THE EQUIPMENT
ANY CONSEQUENCES IF FAILURE ON THE EQUIPMENT?
SPARE PARTS AVAILABLE?
CAN INTERVALS BE EXTENDED PERMANENTLY?
SHOULD PREVENTIVE MAINTENANCE ROUTINES BE MODIFIED?
PERFORMANCE TEST OF THE EQUIPMENT IF NECESSARY
PROPOSED CHANGES
CONSULTATION OFFSHORE ORGANISATION
UPDATING OF THE QUARTERLY PLAN
APPROVED QUARTERLY PLAN
AVAILABLE ON COMPUTER SYSTEM ONSHORE AND OFFSHORE

Requisition of spare parts goes like:

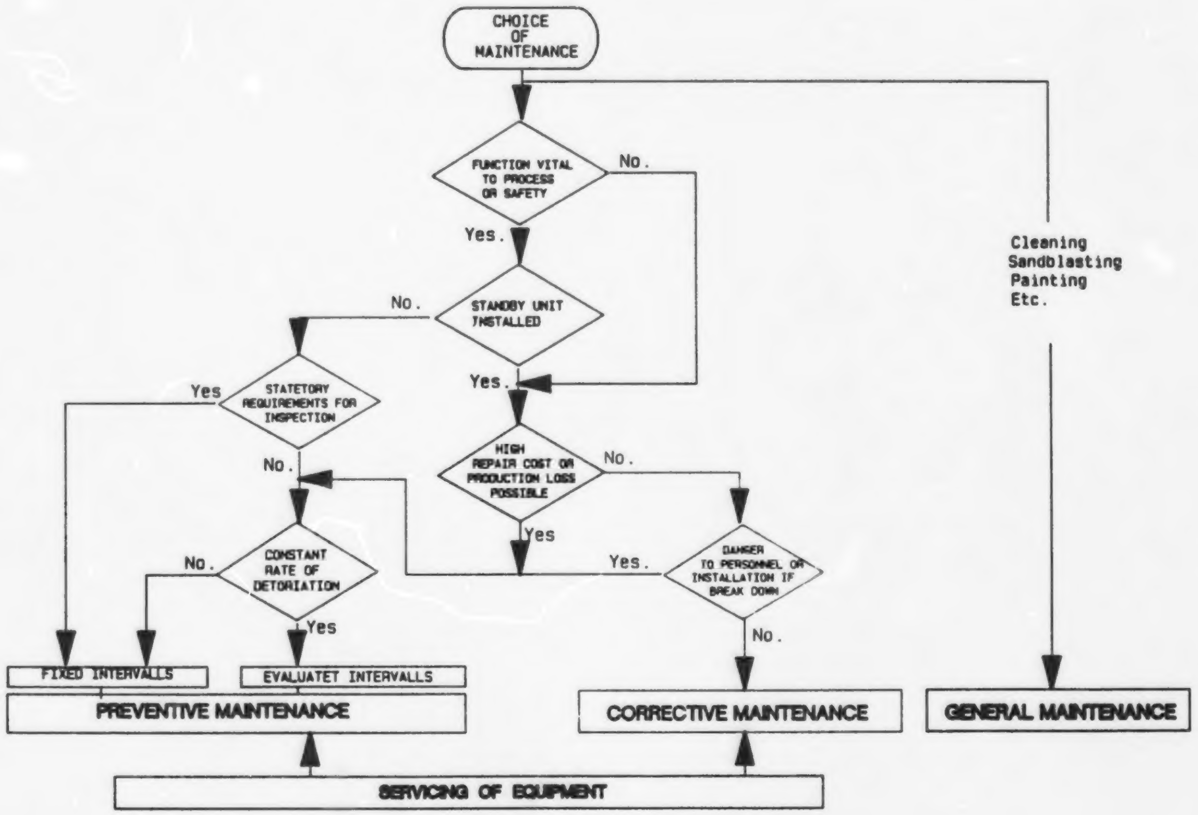
REQUISITION OF SPARE PARTS
USING THE MESC-CODE SYSTEM


REQUIREMENTS
1.
2.
3.
BY MESC No.
BY TAG No.
BY MAKER`S SERIAL/TYPE No.
SPIR FORM
GENERAL ARTICLE REGISTER
(MESC-MAKER`S No.)
IDENTIFY MESC-CODE
STOCK CATALOGUE
PURCHASING SPECIFICATION
REQUISITION
PURCHASE ORDER

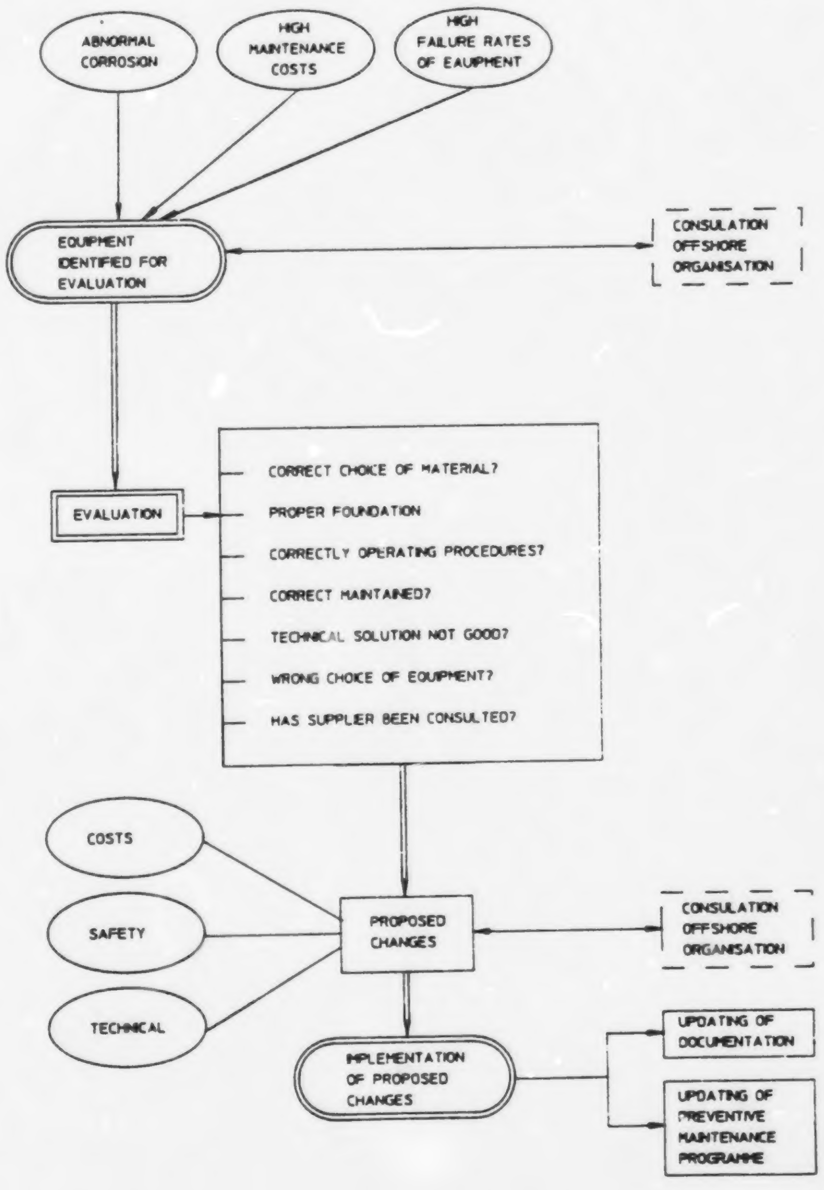
Evaluation of spare parts on all systems are done as:


SPARE PARTS
IS IT MOST LIKELY THAT THE PART WILL FAIL
No.
Yes.
IS THE EQUIPMENT VITAL TO PRODUCTION OR SAFETY
No.
Yes
IS THE PART A NORMAL STOCK ITEM FROM SUPPLIERS
No.
Yes.
IS THE PART VITAL FOR OPERATING THE EQUIPMENT
No.
Yes.
NOT STOCK ITEMS
NOT STOCK ITEMS IF ACCEPTABLE DELIVERY TIME
STOCK ITEMS

CHOICE – TYPE OF MAINTENANCE


CHOICE OF MAINTENANCE
FUNCTION VITAL TO PROCESS OR SAFETY
No.
Yes.
STANDBY UNIT INSTALLED
No.
Yes.
Cleaning
Sandblasting
Painting
Etc.
STATETORY REQUIREMENTS FOR INSPECTION
Yes
No.
HIGH REPAIR COST OR PRODUCTION LOSS POSSIBLE
No.
Yes
CONSTANT RATE OF DETORIATION
No.
Yes
DANGER TO PERSONNEL OR INSTALLATION IF BREAK DOWN
Yes.
No.
FIXED INTERVALLS
EVALUATET INTERVALLS
PREVENTIVE MAINTENANCE
CORRECTIVE MAINTENANCE
GENERAL MAINTENANCE
SERVICING OF EQUIPMENT

EVALUATION OF FAILURE OF EQUIPMENT


ABNORMAL CORROSION
HIGH MAINTENANCE COSTS
HIGH FAILURE RATES OF EAUPMENT
EQUIPMENT IDENTIFIED FOR EVALUATION
CONSULATION OFFSHORE ORGANISATION
EVALUATION
CORRECT CHOICE OF MATERIAL?
PROPER FOUNDATION
CORRECTLY OPERATING PROCEDURES?
CORRECT MAINTAINED?
TECHNICAL SOLUTION NOT GOOD?
WRONG CHOICE OF EQUIPMENT?
HAS SUPPLIER BEEN CONSULTED?
COSTS
SAFETY
TECHNICAL
PROPOSED CHANGES
CONSULATION OFFSHORE ORGANISATION
IMPLEMENTATION OF PROPOSED CHANGES
UPDATING OF DOCUMENTATION
UPDATING OF PREVENTIVE MAINTENANCE PROGRAMME

8. COST IMPACT.

By implementing a maintenance system as outlined in above, the cost impact in relation to classic maintenance discipline oriented, and calendar based, service maintenance, cost cut is estimated to:

- Personell cost offshore/onshore	- (10 %)
- Materials cost	- (5 %)
- Cost due to improved oversight	- (5 %)
- Reduction of total maintenance costs	20 %

A tool to achieve this is the computer based system, and an organization structured according to systems working in teams, not according to disciplines working individually.

SPEAKER : **LESLIE GOMM**

COMPANY : **BAILEY CONTROLS**

LOCATION : **BURLINGTON, ONTARIO, CANADA**

TOPIC : **A NEW GENERATION CONTROL SYSTEM**

BIOGRAPHY: Leslie Gomm, a Chemical Engineer from Queen's University, Kingston, Ontario, has been with Bailey Canada for over two years. Her experience at Bailey includes system engineering, applications engineering and marketing support. She spent six months in Bergen Norway, working with Petrovest on the Veslefrikk Project. Prior to Bailey, Leslie worked for Petro Canada as Petroleum Engineer.

ABSTRACT

The Statoil Veslefrikk Platform, now in its final stages of construction, is a state-of-the-art Offshore Rig design.

Production Process Control and Data Acquisition, Fire & Gas Safety System and Safety Shutdown functions are all integrated in an advanced Distributed Control System. This system is a departure from the traditional discrete function systems. This integration represents the present and future configuration in Offshore Platform control strategy.

The distributed control functions are in constant communication with each other and the operators in the Central Control Room via a redundant plant loop snaking throughout the platforms. The control functions, though in constant communication, are within themselves redundant and independent. Attractive conventional Mimic/Matrix panels are driven entirely from the distributed system.

The Man-Machine Interface is a "Star Trek" console composed of several high resolution CRT's with ergonomically designed keyboards for process control. The operators can access graphic displays depicting any function in the distributed system through a single keystroke.

Hundreds of powerful state-of-the-art distributed microprocessor controllers keep constant vigilance on the rig to ensure safe and optimal control.

INTRODUCTION

The Statoil Veslefrikk project is located in the 30/3 field in the Norwegian North Sea. The Veslefrikk installation consists of two platforms; a fixed steel jacket supporting the drilling and wellhead platform Veslefrikk A (VFA), and a semi-submersible production platform Veslefrikk B (VFB), with a bridge connection between the two. Power, communication and signal link are via a catenary system suspended from the bridge. Veslefrikk A is normally unmanned and is monitored and controlled from the Central Control Room on Veslefrikk B. Refer to Figure 1.

CONTROL SYSTEM LAYOUT

Process Control and Data Acquisition (PCDA), Emergency Shutdown System/Abandon Platform Shutdown (ESD/APS), and the Fire and Gas System (F&G) monitoring and control functions are all carried out by a Distributed Control system based on the data highway architecture. The Veslefrikk system consists of two redundant plant communication loops. The PCDA and ESD/APS system are located on one redundant loop, and the F&G system is on the second. The two loops communicate with each other over a communications gateway interface. Communication between VFA and VFB is via the two redundant plant loops, with fibre optic modems and cables facilitating the connection between the two platforms. The system is further partitioned based on system functionality with each system performing particular dedicated tasks. The distributed nature of the system maintains full automatic control of the systems even when there is a failure in either communication loop. Refer to Figure 2.

Process Control and Data Acquisition

The PCDA system consists of the production facilities, wellhead (WHL) andProcess Shutdown System (PSD). The primary tasks of the PCDA system is the monitoring and control of process variables and equipment. The Man-Machine Interface is provided through CRT-based operator consoles. The PCDA system will perform control operations of both platforms.

The system is partitioned into functional units and located in Process Control Units (PCU's). Each specific area is controlled by redundant microprocessor controller modules. The communication between each PCU is via a redundant plant loop. This set up provides both stand alone control as well as full capacity for inter-communication with other PCU's and systems and operator display units.

The Wellhead system (WHL) performs sequencing and monitoring of production and injection wells. Due to the importance of the WHL system, safe operation of the system must be maintained at all times. Several safety functions are included in the wellhead system to ensure this high integrity. These functions include the sequential shut-in of a well initiated by pressure ,PSD, or ESD alarms, display of all alarms at the operator interface, and automatic shut-in of wells resulting from a loss of communication with the safety systems or failure of critical inputs. The system is also redundant at the controller level with fail safe options so that if a failure occurs the system can default its safe state.

The Process Shutdown System (PSD) is also contained in the PCDA system, but is functionally independent and utilizes dedicated redundant controller modules. The purpose of the PSD system is to automatically detect abnormal operating conditions within systems or equipment and initiate actions to prevent the uncontrolled release of hydrocarbons. In order to ensure the integrity of the PSD system, its inputs and outputs are also completely separate from the PCDA system.

The PCDA system also interface with other monitoring and control systems via serial interfaces. The serial interfaces are programmed in versatile controller modules using a high level language. These systems include Gas and Oil Metering, Gas Chromatograph, Main Generator, Pac Scan, and sales pipeline interface.

Emergency Shutdown System/Abandoned Platform Shutdown

The Emergency Shutdown System's (ESD) purpose is to minimize the consequences of an emergency situation and provide safe and rapid shutdown of the entire production facility. Its primary function is to stop the flow of hydrocarbons and eliminate any possibility of ignition. The Abandoned Platform Shutdown (APS) will ensure that an abandoned platform is totally depressurized and electrically dead. Both these functions are performed by the same system.

The Veslefrikk ESD system consists of two main parts; VFA ESD system and VFB ESD system. The ESD system is located on the same redundant plant loop as the PCDA/PSD systems. There are also hardwired signals between the ESD, PSD and F&G systems. The system was designed with dual redundancy in order to provide maintenance and modification without being taken offline. All inputs are split forming two inputs to the two systems. The ESD systems consists of two Process Control Units (PCU's), one on VFA and the other on VFB. Within the PCU's there is a set of dual controllers. Each of these controllers contains the identical logic and receives identical inputs from the other systems. Each system controller updates the matrix panel independently, having one LED for each system. The ESD system communicates with the matrix panel via remote I/O Modules.

Communication is achieved between ESD VFA and VFB via the redundant plant loop and hardwire connections. This ensures that the high integrity of the ESD system is maintained at all times. The signals that are hardwired consist of essential ESD and APS system inputs and outputs. These signals are also fully redundant. The plant loop is utilized for status signals between the PCDA and ESD systems. This information is indicated both on the matrix panel and the Man-Machine interface.

Due to the extreme importance of the ESD/APS system, the system must be continuously monitored and maintained. Each system can be deactivated and utilized for testing of new logic and the running of self test functions, while the other maintains monitoring and control. These functions are configured into the controller's logic and are manually initiated. The selftest will ensure that all outputs open and close correctly. The systems also has continuous testing/monitoring of input and output circuits by providing short circuit, open circuit, and earth fault monitoring.

Fire and Gas System

The Veslefrikk Fire and Gas (F&G) system is responsible for the monitoring and operation of all Fire and gas related equipment including detectors, sprinklers, halon, deluge and/or water systems and fire pumps. High integrity of the F&G detection and protection systems is ensured by partitioning of the platform into Super Fire Areas. Each Super Fire Area's logic is contained in an independent redundant controller. Each controller will execute all designated safety functions associated with the particular area.

The areas are arranged on both a functional and geographical basis in order to minimize and localize the areas so that they can be easily manually monitored during any failures. Veslefrikk is divided into ten Super Fire Areas.

The Fire and Gas system resides on the second plant loop. It communicates with the ESD and PCDA systems via a gateway module.

All Field input loops that can cause a fire or gas alarm are monitored for short and open circuit faults. All power supplies feeding field equipment also have earth fault monitoring.

The controller modules associated with each super fire area control both field output slaves and I/O slave associated with a matrix panel. No controller is directly associated with the matrix panel. Output from the controller to the Matrix/mimic panel is via remote I/O modules.

CONTROLLER MODULE

The controller modules used in the Veslefrikk system are intelligent high powered modules which provide one to one redundancy. The redundant controller is continuously updated and should the primary controller fail, the second assumes control instantaneously. This redundancy also provides for on-line logic modification.

The controller modules use the 68000 family of microprocessors to implement functions. The selection and inter-connection of these control functions is accomplished by specifying Function Blocks, referred to as blockware. In addition to this blockware, more sophisticated controllers also support high level languages, such as "C", which was used for Serial Interfaces. These controller modules store all configuration in non-volatile memory.

COMMUNICATION

The distributed communication throughout the Veslefrikk Platforms is based on the data hi-way concept. The data hi-way consists of two redundant plant loops. The PCDA/WHL and ESD/APS systems utilize one plant loop and the Fire and Gas system, a second. Between VFA and VFB communicaton is achieved by fibre optic cable and modems. The two loops communicate with each other via a gateway interface. Fibre optic modems and cables are used for the inter-platform communication.

All messages within the entire system are communicated via the data hi-way on an exception reporting basis. Information is only transmitted when a change has occurred in the data. Signal processing is carried out at the Process Control Unit level. Each process input has a set of exception reporting limits associated with it. When exceeded, its new value is reported to all parts of the system requiring the data. A maximum reporting time is specified to enable data to be reported if there is so change, and a minimum time to ensure that a rapid changing will not saturate the system.

The communication system used in the Veslefrikk project has a high level of security with both the data hi-way and loop interfaces being fully redundant.

The gateway interface utilized in the Veslefrikk system is for monitoring purposes primarily. One gateway interface is located on each plant loop. Through the gateway, each loop receives exception report data from and exercises control to the other plant loop. The gateways communicate with each other via a series of commands and replies over RS 232 serial ports. The gateway has built in diagnostics that ensure high data security.

Serial interfaces are utilized in the system to communicate with devices outside the distributed control system. All interfaces use a high powered controller which executes "C" language programs. The communication between the specialized controllers and the external interface is over an RS 232 cable. The controller receives and transmits signals with protocol for communication which is set up in the software. The "C" software also interfaces with the normal control blockware for integration in the remaining distributed control system.

Remote Input/Output modules facilitate the inter-communication between the Distributed Control System and Mimic/Matrix panels used in both the F&G and ESD/APS systems. The remote I/O modules (RIO) are specifically designed for communication between controller modules and remotely located input and output modules. In both systems, one RIO module is placed locally with the controller modules. A second RIO module is located remotely in the matrix panel. Control information is sent from the local RIO to the remote RIO via a twisted pair cable. This remote RIO actually acts as the master (controller) of the remotely input and output modules. These modules then input and output data to and from the panels. The remote RIO transfers data to the local controller, which then takes appropriate control action.

MAN-MACHINE INTERFACE

The Man-Machine Interface (MMI) functions were provided by both Mimic/Matrix panels and CRT-based operator interface. The PCDA system utilizes the Management Command System (MCS) for monitoring and control of the processes. The ESD/APS and Fire and Gas systems use mimic/matrix panels as their primary operator interface.

The PCDA operator interface consisted of two CRT consoles each complete with slave CRT's. Each operator station was configured identically to provide complete redundancy. Through the dynamic interactive process graphics, full process monitoring and control is achieved. The interface units displays were arranged in such a manner to enable single stroke access to any alarm in the system. This hierarchy is essential for the immediate viewing and acknowledgement of all system and PSD alarms. All alarms were set up to be logged on an event log. Displays are linked to follow the flow of the process throughout the dual-platform system.

The primary Man-Machine Interface for the ESD/APS system is a Matrix panel. The PCDA system operator stations also provide backup display facilities for the ESD system such as valve and trip monitoring, system hardware diagnostics and the performance of system selftests.

The Fire and Gas system utilizes a Mimic/Matrix panel for its main operator interface. A Management Command System is also incorporated in the system with detailed displays of each fire area. The MCS is completely independent and is used primarily for maintenance purposes. Some of the functions include analog indication and trending of gas detectors, isolation of individual detection loops, alarm logging, alarm and fault summaries and system hardware diagnostics.

SUMMARY

The aspect of safety has become a primary concern in the design and implementation of offshore systems. The Bailey NETWORK 90 System being used in the Veslefrikk project provides a fully integrated control system incorporating advanced safety features in conjunction with true distributed control. Examples of this can be seen throughout the Veslefrikk control system. Within each area, whether ESD, F&G or PCDA, the redundant and distributed nature of the system provides the utmost security, reliability and performance. This enables greater process efficiency, improved product quality, and a high level of safety.

REFERENCES

"Control and Monitoring Systems for Production Platforms - Future," technical paper by M.A. Keyes, Bailey Controls Company, Babcock & Wilcox, a McDermot Company, USA, 1987.

"Offshore Distributed Control System," by Larry S. Rice, Bailey Controls Company,Babcock & Wilcox, a McDermot Company, presented to Offshore Mechanics and Artic Engineering (OMAE), March 3, 1987.

"Applications and Issues of Fiber Optics in Commercial Marine Vessels and Platforms," by John Glowe, Bailey Controls, Babcock & Wilcox, a McDermot Company, presented to Symposium on Fiber Optics & Integrated Optoelectronics, August 20, 1987.

"Veslefrikk Detailed Functional Design Specification," from Petrovest A/S and Metz Process Control A/S to Moss Rosenberg Verft A/S, 1988.

VESLEFRIKK

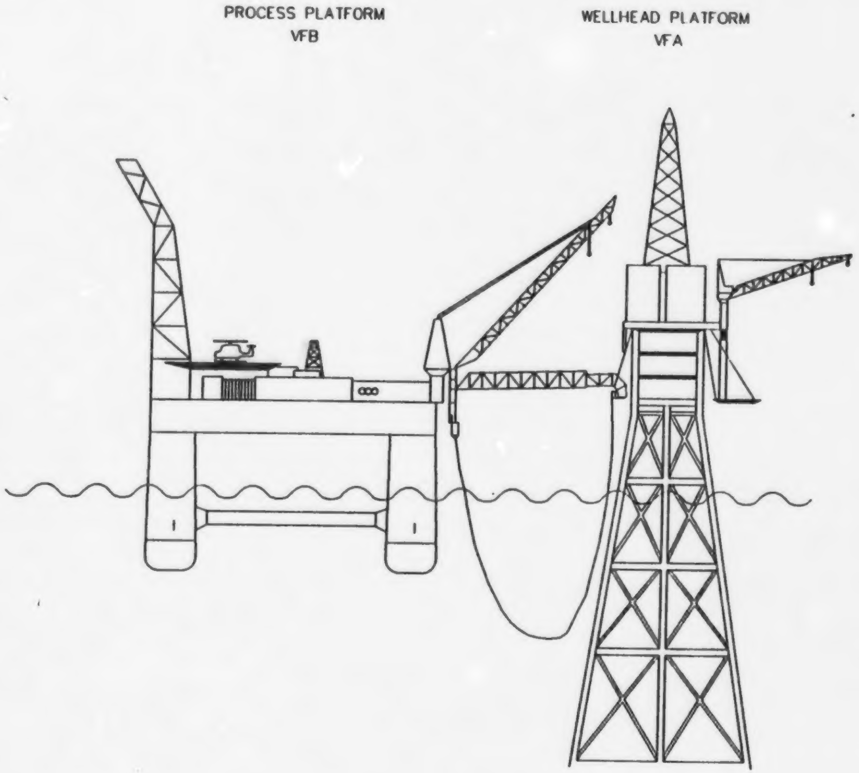
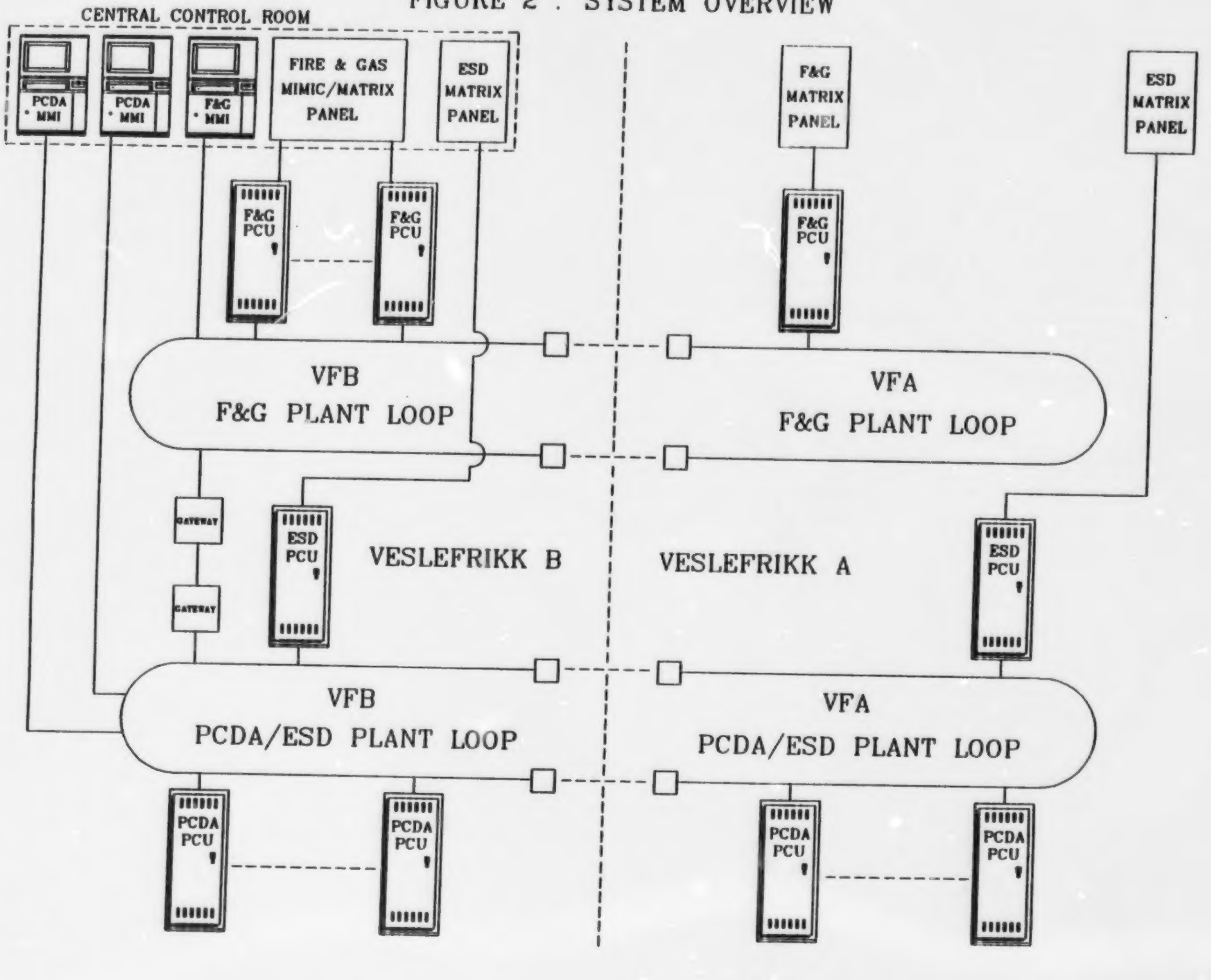

PROCESS PLATFORM
VFB
WELLHEAD PLATFORM
VFA

FIGURE 1

FIGURE 2 : SYSTEM OVERVIEW


CENTRAL CONTROL ROOM
PCDA MMI
PCDA MMI
F&G MMI
FIRE & GAS MIMIC/MATRIX PANEL
ESD MATRIX PANEL
F&G MATRIX PANEL
ESD MATRIX PANEL
F&G PCU
F&G PCU
F&G PCU
VFB F&G PLANT LOOP
VFA F&G PLANT LOOP
GATEWAY
GATEWAY
ESD PCU
VESLEFRIKK B
VESLEFRIKK A
ESD PCU
VFB PCDA/ESD PLANT LOOP
VFA PCDA/ESD PLANT LOOP
PCDA PCU
PCDA PCU
PCDA PCU
PCDA PCU

SPEAKER : WILLIAM PENNEY

COMPANY : UNIVERSITY OF NEWCASTLE UPON TYNE

LOCATION : NEWCASTLE UPON TYNE, ENGLAND

TOPIC : DESIGNING FOR PLATFORM REMOVAL

BIOGRAPHY: William Penney graduated in Naval Architecture from the University of Glasgow in 1962. Research for his Master's degree concerned Cargo Handling and Heavy Lifts. He then worked as an Assistant Naval Architect for Ocean Fleets of Liverpool (Blue Funnel Line), being a member of the team designing the first purpose-built container ships. In 1968 he moved to a lecturing post in the University of Wales at Cardiff where his interests in offshore technology began. After a two years spell as a Principal Research Technologist with P & O Ltd. in London, he took up his present teaching post at the Unversity of Newcastle Upon Tyne in 1976. Vehicle Design as well as teaching Basic Naval Architecture and Stability to first and second year students. His research interests concern the funcational design and stability of offshore platform removal. He is a Chartered Engineer and Fellow of the Royal Institution of Naval Architects and a Fellow and Council Member of the Society for Underwater Technology.

ABSTRACT

The Hibernia gravity base structure (GBS) will be designed with a view to ultimate removal once it has completed its oil production service. The general requirement is that all platforms whether built in steel or concrete will have to be removed partially or entirely. Consideration must be given to legal and physical aspects in so far as they affect the choice of installation type and method intended for its removal. Methods of removing topsides and steel/concrete jacket structures are discussed with particular regard to the stability of the GBS. Designers should be aware of the problems associated with removal and incorporate suitable features at the time of a structure's inception.

> *Condition 10: That the Proponent (Mobil Oil Canada Ltd and its venture partners) design all subsea facilities such that, upon termination of production, they will be capable of being covered or removed so that the area is returned to a fishable condition, and design the Gravity Base Structure so that it could be removed if the Authorities at that time so require.*
>
> Hibernia Development Plan(1)

1. INTRODUCTION

There is a growing realisation that one day offshore oil/gas production installations will indeed have to be considered for removal and disposal in some way. Despite the intent in the 1958 Geneva Convention that a coastal state's activities should not result in any unjustifiable interference with other uses of the sea (Article 5.1) and that any installation which is abandoned or disused must be entirely removed (Article 5.5), legislators did not then appreciate how large some of the installations would become and oil companies probably hoped that the impending problem would simply evaporate, i.e. that the larger platforms would be allowed to remain in place for ever, or until they collapsed. New guidelines drawn up by the International Maritime Organisation (IMO) which are expected to be ratified in Autumn 1989 have brought a sharp reminder that the removal of a platform could be demanded and hence that associated costs should be included in cash flow calculations. This situation may affect the date at which a particular platform is deemed to have become uneconomic and therefore that production should cease.

Canada, with her fledgling offshore operations along the Atlantic seaboard, has a unique opportunity to benefit from the experience of others in the certain knowledge that platform removals will have to be undertaken either in whole or in part. In response to the Hibernia Proponent's claim (1) that "... any decommissioning procedures formulated now would only be speculative", the Assessment Panel noted that "failing to provide in the design for eventual removal would increase the complexity and costs of so doing, if a decision to remove the facilities were to be made by the Authorities of the day". Although the Panel concluded that there might be temporary advantages of using the Gravity Base Structure for other purposes, it recommended that due to the consequences of long-term structural deterioration the GBS be designed in such a way that it could be refloated and removed if necessary. Installation contractors who have formed themselves into international consortia are well aware of the problems to be faced during removal, but certifying authorities and government agencies must prepare themselves in asking searching questions and in appreciating the financial implications as they now begin to grant approval for the installation of platforms and associated structures. Removal is unlikely to be an easy task and is not simply the reverse procedure to the initial installation. Furthermore, if removal is to be enforced, collective circumstances considered during the selection of the major pieces of production equipment could favour a floating production system instead of a gravity based installation.

2. ENVIRONMENTAL REGIMEN

Satisfactory design can be enhanced through an awareness of the inter-dependencies of environmental conditions which we shall consider here includes legal, physical and equipment aspects. Each region has its own peculiarities and the relative importance of any one factor could be expected to differ from place to place and should be weighted in accordance with national priorities. Experience gained in one region can be adapted to suit local needs and conditions.

2.1 Legal

The general requirement proposed by IMO is for abandoned structures on any continental shelf to be removed, except where non-removal or partial removal is consistent with certain standards (2). A coastal state may impose more stringent requirements for existing or future installations. IMO proposes that structures standing in less than 75m and weighing less than 4000 tonnes should be entirely removed and in cases of partial removal an unobstructed water column of at least 55m should be left above any remains. However, after 1997 no installation should be placed on any continental shelf unless its design is such that entire removal would be feasible. The means of removal should not cause a significant adverse effect on living resources of the marine environment. A coastal state may allow an installation to remain in place if it will serve a new purpose or will not cause unjustifiable interference with other uses of the sea. It is this relief which may give rise to arguments between oil companies and the fishing community as well as those engaged in other subsea activities. The situation for Hibernia has already been stated and presumably will be specified in the approval documentation, but decisions will have to be reached for other platforms in the future.

2.2 Physical

Hibernia is located in a water depth of only 78-84m in which a steel jacket structure would normally be expected. The high probability of collisions from icebergs has been an overriding priority in the selection of a concrete structure. It must be designed to withstand impact from bergs displacing up to 600,000 tonnes which necessitates high frictional attachments to the seabed using skirt piles. These same piles must be cut prior to eventual removal and so introduces a compromise during the design work about the degree and quantity of attachment. Ease of access to the piles or means of cutting them remotely could also be considered.

Soil conditions have a major impact upon selection of steel or concrete platforms and their detailed design. Heavy weight concrete gravity structures inevitably sink into the seabed by an amount depending upon soil strength; the adhesive forces have to be overcome before removal can take place and to achieve this water or compressed air would be pumped in beneath the base of the structure. Suitable pipework must therefore be installed at the time of construction, but blanked off to prevent clogging with silt or accidental flooding. Break-out procedures may take several days or even weeks to become effective depending on the nature of the soil and the amount of incentive work carried out around the base (3).

Wind and wave conditions are unlikely to be so important as during installation procedures. A number of service and monitoring craft will be in the vicinity, but from the point of view of safety the weather forecast should be good for several days ahead because once the break-out process starts it will be difficult to halt or delay it.

2.3 Equipment

The easiest solution is to leave an abandoned platform in place, providing it is regularly inspected and maintained in a safe condition. However, apart from the desire to keep the seas free of redundant structures there is a danger that as a platform ages, despite regular maintenance, it could become ever more costly and eventually too dangerous to remove. This was one of the reasons given for the apparently very high cost of completely removing the remains of ill-fated Piper Alpha steel jacket. Oil companies and their partners will no doubt seek ways of extending a field's lifetime (e.g. Enhanced Oil Recovery) and there are several examples in the North Sea of tying-in adjacent marginal fields by pipelines from minimum services platforms or satellite well heads. But that prospect is probably unacceptable for Canadian coastal waters where the iceberg scouring risk is high. The alternative is to look at floating production systems (indications for Terra Nova) which might be re-usable at another field. Managing the iceberg risk has got to be carefully assessed and with it any extra costs. This is the inter-dependency spoken about previously that in some regions a concrete gravity based structure maybe the only solution for a production platform. Any difficulties perceived in its removal have got to be resolved at the design stage.

3. REMOVAL OPTIONS

Many technical papers have addressed this problem in comparative overview (4) and in detail (5),(6) and industry awaits experience from removing the first big platform. About 500 small ones have been removed from the shallow waters of the Mexican Gulf, and in the North Sea the only events to date are the removal of a small satellite platform from the West Sole field in 1978 and another from the Dutch sector in 1988. Piper Alpha was a special case where toppling was considered to be the only safe recourse: the Government has said that this is not seen as a precedent.

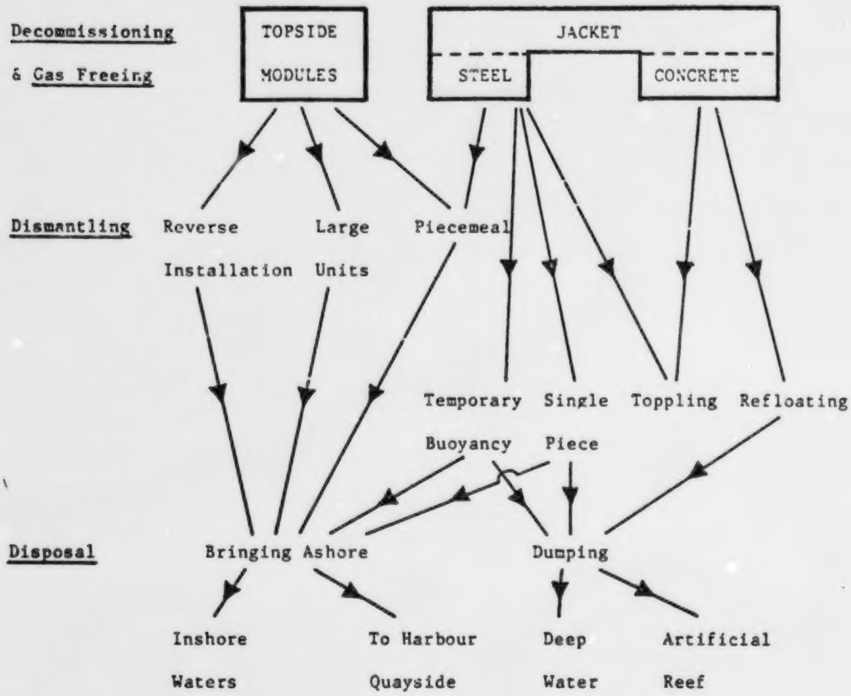

Decommissioning
& Gas Freeing
TOPSIDE
MODULES
JACKET
STEEL
CONCRETE
Dismantling
Reverse
Installation
Large
Units
Piecemeal
Temporary
Buoyancy
Single
Piece
Toppling
Refloating
Disposal
Bringing Ashore
Dumping
Inshore
Waters
To Harbour
Quayside
Deep
Water
Artificial
Reef

Fig.1. The Prinicpal Options and Procedures for Removing Abandoned Platforms.

The overall range of options for both steel and concrete installations are summarised in Fig.1 (4). Although we are now assessing the Canadian Atlantic scene with the prospect of a concrete structure at Hibernia, brief mention will be made of steel structures if only for purposes of comparison. Problems associated with removal of topsides will be similar whether the jacket is built of steel or concrete, though the extent of removal may be very different. However, before any removal can take place, all oil/gas wells must be plugged and the platform totally purged of all hazardous materials and gaseous accumulations before any cutting, burning or welding work can take place. If there is an integrated storage facility, then tanks may have to be cleaned before the structure is dumped in deep water. This is the decommissioning stage.

3.1 Topsides

Jacket structures are installed offshore in a single piece (there are exceptions for very deep waters). Those in steel include barge-launched, lift- and-lower by crane, and self-floaters which like the concrete structure are towed out to site before being ballasted down. Concrete structures have their topsides installed as a single unit by ballasting the jacket almost to full submergence in deep sheltered coastal waters, whereas in the case of a steel jacket the topsides are raised into place once the structure is piled on its final site. Those topsides may come either as a few integrated structures weighing up to 10,000 tonnes each, or as perhaps a dozen units averaging only 2-3,000 tonnes. It is important to realise this when preparing for deconstruction which in fact means during the initial design stage. The trend is to use bigger crane vessels for installation and consequentially to design for larger topsides modules. This rather commits the platform owner to have it dismantled in the same way because smaller units would have to be temporarily fitted with additional stregthening to enable lifting to be carried out safely.

At this juncture it is worth mentioning that during the deconstruction phase safety arrangements must be foreseen and maintained. Damage to structure which is no longer usable may not matter, but a unit suddenly becoming detached from a ship or semi-submersible's crane due to inadequate stiffening or poor re-welding of lifting eye pads can have a disasterous effect upon the vessel's dynamic stability. Indeed the vessel could capsize (4). Rigorous attention must be given to all welding details bearing in mind the less than ideal welding environment while at sea. The obvious precaution is to prepare for dismantling from the start.

3.2 Concrete Jacket

Concrete structures may be installed complete with their topsides, yet when it comes to removal some of that topsides weight is likely to need lifting off beforehand. The reason is adhesion of the base to the seabed and the consequential need for substantial positive buoyancy to effect lift off. Ballast is pumped into the storage cells in the base for two purposes, in the first instance to provide adequate stability while under tow and latterly with further ballasting to achieve set-down at the designated site. To remove the platform off the seabed ballast is discharged as well as being injected into cells beneath the periphery of the base [6]. Some differential pressurisation across the base can help to break up the adhesion to the soil beneath.

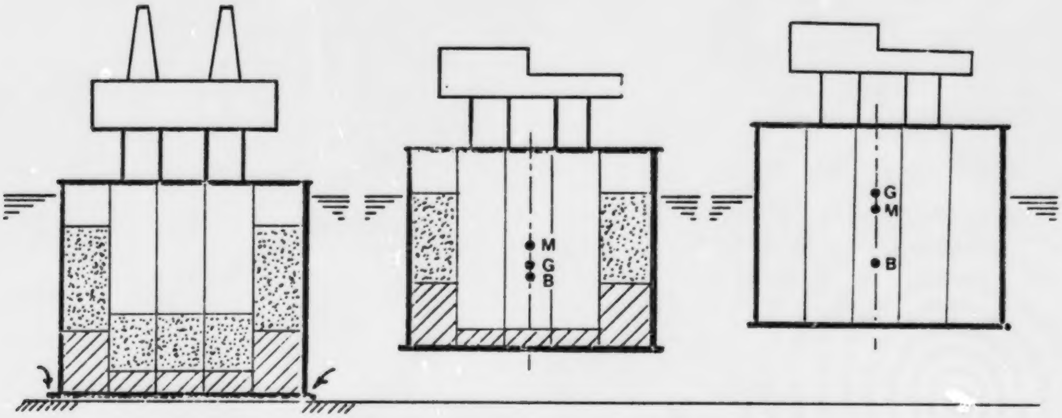


Fig.2. Potential Instability of a GBS during deballasting.

The resultant buoyancy upthrust obviously increases as more ballast is discharged, so when the structure finally breaks free it will rise to the surface where it could have negative stability and capsize Fig.2. To illustrate this, for the planned Hibernia structure, Table 1 shows the variation of metacentric height (GM) if floating freely on the surface against the net buoyancy upthrust (equals displacement while on the seabed minus free floating displacement). Several assumptions have had to be made due to lack of data, but allowance has been made for weight and vertical centroids of base structure, shaft columns and topsides which indicated a centroid (KG) of 52.9m for a mass estimated to be about 393,000 tonnes. The base structure has a diameter of 100m, height of 85m and a displacement of about 644,000 tonnes when founded in a water depth of 80m [1].

TABLE 1 - Variation in Freeing Upthrust from the Seabed against subsequent metacentric height estimated for the Hibernia concrete platform

Freefloating displacement (tonnes)	Estimated ballast (tonnes)	Net Force of buoyancy (tonnes)	Freefloating draught (m)	KB (m)	BM (m)	KG (m)	GM (m)
393,000	0	251,000	48.8	24.4	12.8	52.9	-15.7
493,000	100,000	151,000	61.2	30.6	10.2	42.8	-2.0
593,000	200,000	51,000	73.6	36.8	8.5	36.7	+8.6
644,000	251,000	0	–	(bottom founded)			

Designers need to consider whether the net force of buoyancy which helps to free the gravity base from the seabed is sufficient. It can be increased only at the expense of potential instability at the sea surface. Note also that the diameter of the base has a vital affect upon stability while it is in a free-floating condition.

3.3 Steel Jacket

After the topsides are removed in either large or small units, partial or total removal of the massive space frame structure must be undertaken. Obviously it is cheaper to only partly remove leaving the 55m clear water column above the remainder. Whatever the extent of removal a substantial amount of underwater work will be necessary to cut through tubular legs and bracing members, or through the piles pinning the jacket to the seabed in the event of total removal. Large jackets cannot be lifted as a single piece with existing equipment, although there have been proposals for converting redundant oil tankers to this purpose. Refloatation may be employed if that was the method by which the platform was installed in the first place, but this requires assured integrity of the buoyancy spaces with perhaps refitting and additions to the integral pipework. Contractors must have confidence that spaces will remain intact under the hydrostatic pressures needed to evacuate those which may have become filled with water. A piecemeal approach to jacket dismemberment could lead to the use of smaller crane ships or semi-submersibles or even suitably converted drilling rigs which already contain substantial accommodatin for the workforce. Every piece lifted must have a pre-calculated weight and centroid taking account of marine growth, structural deviations and through-water drag forces. A further method is to topple the jacket in situ leaving the structure laid along the seabed providing it is below the 55m water depth.

3.4 Dumping

Steel from abandoned platforms may be brought ashore for reprocessing, but it is unlikely that similar recovery could be achieved for concrete. The proposal is to refloat, tow into deep water and scuttle and it is claimed that this is allowed within the London Dumping Convention. Steel structures could be similarly dumped, the floaters merely being reflooded or pieces loaded aboard barges being simply tipped into the deep ocean. Recovery of structures ashore might be preferred for environmental reasons, but at much higher cost and for almost no financial gain. If it is demanded that structures be brought ashore then features might be incorporated or retained after fabrication to make this easier. It will be appreciated that companies would be reluctant to pay for extra features which will not be used until many years hence.

3.5 Underwater Cutting

Many papers have been published on underwater cutting techniques, suffice it to say here that structures which will ultimately have to be deconstructed should have ready means included in their design for ease of cutting into smaller sections if that is the approved intention. A recent paper (7) discusses ten cutting methods of which explosives, water jet, oxy-fuel and thermic lance have been tried and tested during the few examples of decommissioning.

4. SOME GUIDES FOR DESIGNERS .

Any guidance one can give will clearly depend whether the main jacket structure is built in steel or concrete. In so far as the topsides are concerned removal techniques are similar, but the extent of removal needed off a concrete jacket must be calculated against expected free-floating stability. Above all, designers should think and plan ahead towards feasible removal in the light of current guidelines. Indeed, the U.K. Department of Energy's Annex B approval must contain a scheme for removal together with the field development plan. Some suggestions include the following:

Topsides

(i) Retain lifting lugs or strong attachment points within modules.
(ii) Decide whether piecemeal deconstruction is to be an option or that the module erection programme can or will be reversed.

Concrete Designs

(iii) Retain piping services and valves, though unless these services are regularly maintained they may not be in a fit condition when the time comes to re-use them.
(iv) Provide for water injection points in skirt region.
(v) Install provision for progress monitoring.

(vi) Endeavour to prevent soil adhesion to mud-mat during refloatation.
(vii) Arrange easy access to pile chambers, or can the mud-mat be made detachable?

Steel Design

(viii) Design structural members to accept floatation tanks or other lifting appliances.
(ix) Arrange structure to suit access for underwater cutting or placement of explosive charges.
(x) Arrange structure for ease of toppling, perhaps through sub-division into a pair of half-jackets.
(xi) Large tubular members to be adaptable as buoyancy chambers, or to have additional compartments.

5. CLOSURE

Platform removal in one form or another is inevitable. Generally applications do not pose any insuperable difficulties, but some very high costs will be incurred. While identified platform owners may attempt a legal fillibuster to extend the time when abandonment could become enforceable they must still endeavour to include acceptable and effective removal schemes at minimum cost. The question is how much investment in removal should be included at the design stage? So far as just Hibernia is concerned, removal seems assured and that should applu to all platforms after 1997. With that in mind, oil companies may be encouraged to look at alternative, readily uprooted means of productions which could give added impetus to floating production systems if environmental conditions permit.

REFERENCES

(1) Canada-Newfoundland Offshore Petroleum Board. Decision 86.01, Application for Approval, Hibernia Development Plan. St.John's Newfoundland, June 1986.

(2) International Maritime Organisation, "Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone". Circular and Annex M.Sc./Circ. 490, 4th May, 1988. IMO, London.

(3) Kerr, D., Aldridge, T.R. Ffrench, R.G. "Removal of Gravity Platforms", Proceedings, Decommissioning and Removal of Offshore Structures Conference, London, 1989. IBC Technical Services Limited, London.

(4) Penney, P.W. "Some Aspects of the Removal of Offshore Production Platforms". Trans. North East Coast Institution of Engineers and Shipbuilders, Vol.104, 1987-1988, pp.129-141.

(5) Ramzan, F.A., Blanken, D.T., and Rawstron, P.J.M., "Technical and Marine Requirements for the Complete Removal of a Mid-North Sea Platform Structure" (steel). Proceedings of First International Conference on Decommissioning Offshore, Onshore and Nuclear Works. UMIST, Manchester, 1988. I.L.Whyte, Ed. Thomas Telford Ltd., London, pp.43-54.

(6) Fosker, T. "Removal of Condeep Concrete Gravity Platforms". Proceedings of the Eighth International Conference on Offshore Mechanics and Arctic Engineering, The Hague, 1989. pp.241-248.

(7) Ebdon, R.W. and Ellinas, C.P. "Decommissioning and Removal of Offshore Structures: A state of the Art." Ibid., ref.6, pp.215-231.

SPEAKERS : DAVID HEWLETT & PAUL WILSON

COMPANY : NORTEK ENGINEERING INC.

LOCATION : ST. JOHN'S, NEWFOUNDLAND, CANADA

TOPIC : TECHNIQUES FOR TOPSIDE WEIGHT REDUCTION

BIOGRAPHY: David G. Hewlett, P. Eng., graduated with a degree in mechanical engineering form Memorial University of Newfoundland in 1985. Since that time, he has been involved in various aspects of offshore petroleum exploration and production, including service industry, construction, QA/QC and conceptual design studies.

His most significant offshore experience includes field engineering during the construction and atshore hook-up of the Gullfaks B MSF at Moss-Rosenberg Verft in Stavanger, Norway, as well as the "Terra Nova Pre-Engineering Study" for the Government of Newfoundland and Labrador.

BIOGRAPHY: Paul Wilson is in his final year of the civil engineering program at Memorial University of Newfoundland.

During his work term employment with Nortek Engineering he performed investigations into the protection of subsea facilities from iceberg scouring, and quick disconnect systems for marine production risers, as well as being involved in the "Terra Nova Pre-Engineering Study".

ABSTRACT

Reduced oil prices, development of marginal oil fields, and progression into deeper waters have all contributed to the need for cost effective offshore developments. Topside weight reduction has become a serious topic of late, and the survival of many future offshore projects hinges on the savings it promises. Put simply, lighter platforms save money.

This paper is an overview of topside weight reduction techniques incorporating aspects of front end engineering, the use of new materials and alternative fabrication techniques, and innovative equipment technology. Several examples of their application in the North Sea area are presented.

INTRODUCTION

Topside weight, space and cost savings are possible in several areas. Although the effect of individual items may only be nominal, significant savings can be realized when several are combined. Equally important as the combination of individual weight savings, is the influence of the "knock-on" effect, whereby improvements in one area or system can trigger improvements in other associated systems because of the highly integrated nature of topsides design.

This paper outlines numerous methods of reducing total topside weight on fixed production platforms, as well as floating production systems, drill ships, barges, etc. It focuses on the physical weight and space savings attainable using these methods, many of which are simply good engineering practice.

The weight reduction techniques are classified into three main divisions:

- Front End Engineering
- Structural Design / Materials
- Innovative Equipment Technology

The paper was prepared based on information gathered from publications, technical papers, etc. regarding topside weight reduction, as well as our own investigations into this area.

FRONT END ENGINEERING

Front end engineering (FEE) involves optimization of platform facilities during the planning and design stages. Early in the design process, the platform requirements should be identified and carefully assessed, and facilities allocated to support these platform "needs" (not the often unnecessary "wants" of the platform operator). The past practice of over design, especially associated with future processing facilities, must be re-evaluated if "leaner" designs are to be expected.

The following section is an overview of several FEE practices which can lead to significant topside weight reductions.

Processing: The optimization of the number of oil-gas-water separation trains, separation stages and gas compression trains is an attractive means of reducing topside weight.

Put simply, the platform daily production rate is derived from an economic reservoir withdrawal rate, related to reservoir uncertainty and design contingency. The size and number of separation trains are established to ensure that high production regularity can be achieved.

It has been suggested that a single production train should be seriously considered where the production rate permits, however this solution may not perform at the 95% uptime demanded by industry. The most sensible option is to use two separation trains, but "piggyback" horizontal separators so that the plot area of only a single train is utilized.

The number of separation stages also warrants close examination. Multi-stage separation is primarily used to maximize the amount of oil recovered from well fluids. The additional revenues of increased oil recovery must be weighed against the weight and capital cost penalties in order to optimize the number of stages. Process treatment offshore should be limited to that which is necessary for safe handling of the product and transporting it to shore. **(1,2)**

Power generation: The selection of power generation equipment requires careful attention. To determine the peak power loads, the prime movers must be selected for the foremost power consumers on board the platform, i.e. the crude-shipping pumps, gas compression equipment and seawater injection pumps.

The decision to use a central power generation plant versus individual direct drive gas-turbines must be made on the basis of the size/weight of the prime movers, starting loads and fuel costs. Another important consideration is that exhaust gases from gas-turbine drivers scattered throughout a platform may create hazards in some wind conditions or in the downwash created by helicopters.

Power generation facilities should be optimized based on the phased power consumption requirements for drilling, personnel support, reservoir support and production. Phasing allows use of power generation equipment formerly used for drilling (often kept independent of the main power plant) later in the field life for backup/standby duty or for future increases of production/reservoir support power loads.

When determining the amount of power generation backup, water injection can be considered an interruptible service to permit a temporary power consumption increase to be met. **(1)**

Equipment options: Considerable weight and space savings can be achieved for a number of equipment items through careful evaluation and selection.

Often there are significant differences in the weights and sizes of equipment items with similar performance characteristics from different vendors. In these situations, weight and size should be considered just as important as capital cost when selecting the best unit.

Back-up/standby equipment should be minimized and used only when absolutely necessary.

Several examples of weight and space saving equipment options are as follows (ref. Figure 1):

- Use centrifugal gas compressors instead of reciprocating units in high pressure applications. Screw compressors should be considered as an alternative to either centrifugal or reciprocating compressors in medium pressure applications. Screw compressors can save one-half the plot area and up to two-thirds the weight of a comparable reciprocating unit. **(3)**

- Use screw instead of reciprocating air compressors for weight and space savings. For a duty of 800-scfm, for example, a screw unit would weigh about one-half to one-third as much as a reciprocating unit of the same rating. **(1,3)**

- Consider using vertical centrifugal gas/condensate separators instead of demister pad type gas scrubbers for high gas rate/small condensate rate duties. Weight savings up to 50% may be achieved in some applications. **(2,3)**

- In-line pumps, up to 400 bhp, offer space and weight savings over regular horizontal pumps. For moderate flow rates, special in-line pump designs can offer considerable weight and space savings over reciprocating pumps. It should be noted however, that the capital cost of achieving weight and space savings in pump design is slightly higher than non-compact designs. **(2,3)**

- Consider using submersible seawater lift pumps for weight and space savings.

- Gas engine drivers weigh about 10 - 15% less than diesel or dual-fueled drivers. 50 Hz electric motors and associated switchgear are usually 15 - 30% heavier than 60 Hz electric motors. Aero-derivative turbine drivers offer significant weight saving and competitive maintenance cycles over industrial turbines for applications above 10,000 bhp. **(3)**

- A vacuum-type sewage treatment plant is up to 50% lighter than a conventional unit. **(3)** Compared to a conventional gravity sewage system, a vacuum sewage system offers 90% reduction in sewage volume which in turn means smaller sewage and holding tanks, reduced water supply systems, smaller treatment plants and smaller diameter piping.

- A reverse osmosis (RO) water making facility offers weight and space savings because of its minimal spare equipment requirements. RO units need only a spare pump rather than a spare boiler as required by other methods. **(3)**

- Consider using crane pedestals, jacket legs, box girder structural members, idle production vessels, etc. as temporary or permanent storage compartments for potable water, diesel, corrosion inhibitors, etc.. **(2,3)**

Layout and piping: An efficient equipment layout is fundamental for achieving low topside weight. Equipment layout and orientation should be optimized to minimize plot plans, piping and cable runs, while at the same time allowing maintainability. Piping runs should be kept as short as possible, with the fewest bends and minimal valving.

Lightweight valves should be used whenever possible and the use of fibre reinforced plastic (FRP) piping for seawater service should be seriously considered. **(2)**

Future facilities: Equipment packages that are not required during development drilling and early production, do not need to be installed on the platform initially. Installation of future production equipment may be deferred or phased, using drilling operations weight and space. Additional weight and space can be made available by stripping drilling modules to that required for workover operations only. **(1)**

The drilling modules of the Shell/Esso Eider platform, for example, are removable and can be lifted off and replaced with a much lighter workover rig after the completion of development drilling.

Platform supply frequency: Considerable weight and space savings can be realized if platform bulk storage silo and liquid tankage capacities can be reduced by decreasing the resupply period. A

10 - 14 day resupply period is commonly used for design, however at least half that period should be sufficient based on current supply boat logistics.

Additionally, silo and tank capacities/configurations should be optimized based on consumption histograms. Studies performed for the Sleipner and Oseberg fields have revealed that one of the keys to reducing drilling facilities weight lies with the storage and handling of bulk materials. The bulk tanks within the drilling area are usually dedicated for one material only, like barite or bentonite. However, the maximum consumption of these chemicals generally do not occur simultaneously. A storage arrangement consisting of a number of smaller "multiple usage" tanks would allow the tanks to remain fuller for longer periods and at the same time reduce the total bulk storage volume. If rectangular atmospheric storage tanks are used instead of heavy cylindrical high pressure tanks, weight and space reductions of 40 and 15 percent respectively are said to be possible. **(4)**

Satellite platforms: The development of marginal oil fields require cost effective solutions. Satellite platforms, designed to utilize the surplus capacity emerging on existing platforms as they come off plateau production, are much more economically attractive than conventional full production standalone platforms.

The Shell/Esso Eider platform, for example, was designed with minimum platform facilities, instead using facilities on the neighboring Shell/Esso North Cormorant and Tern platforms. First stage gas/oil separation and primary water removal are performed at Eider before export to North Cormorant to take advantage of its spare processing capacity. Reservoir pressure maintenance is provided by seawater imported at injection pressure from Tern. After development drilling and production stabilization, the Eider platform will be eventually left unmanned and remotely controlled from North Cormorant.

STRUCTURAL DESIGN / MATERIALS

Significant weight savings can be realized in the area of structural design through the use of new materials, larger modules and integrated deck structures.

New materials: Aluminum, high strength steels and fiber reinforced plastics are being introduced in a wide range of topside applications.

Aluminum in particular has found widespread applications in the Norwegian offshore industry, and products and constructions can be found on virtually all fixed installations. During the last 2 - 3 years aluminum has been used for helidecks, bridges and secondary constructions, and more recently slated for use in fire classified modules and complete living quarters. The distinct advantage of aluminum over the traditional steel structures is its ability to be manufactured in shapes that will reduce overall fabrication costs. This is particularly important since the cost of aluminum is acknowledged to be greater than that of steel. In addition aluminum has a particularly good resistance to sea water.

Aluminum sheets and plates can be produced in all shapes similar to steel, while the extrusion process allows endless possibilities for functional designs. The formability and high strength of aluminum has been utilized on some major North Sea oil development projects over the last few years, notably Norsk Hydro's Oseberg A platform.

On the Oseberg A, aluminum was utilized extensively on topsides facilities including the helideck framework, hangar, stairways and railings as well as weather walling, cable ladders, ventilation ducting, computer floors, maintenance gantry and escape towers. In addition the helideck was made entirely out of aluminum. This use of aluminum amounted to a total weight saving of some 600 tonnes. Based on the relative densities of steel and aluminum, a 50% weight reduction for loaded items and a 66% weight reduction for non critical components can be expected. These weight savings however could have been much higher (in the range of 2000 tonnes) had aluminum been considered from the start of the project. **(5)**

With the design of Saga Petroleum's Snorre TLP came a major breakthrough in the use of aluminum in offshore structures. This is the first time major structural components of a full sized accommodation module, including walls and floors, are scheduled to be fabricated from aluminum. Compared with a conventional, equivalent steel module this would amount to a weight saving of approximately 600 tonnes. To aid in the development of fabrication methods for this project, a full scale aluminum prototype was built based on a section from one floor of the Gullfaks B accommodation module. The deck structure of the prototype unit consists of beams, stringers and plate, which are all built up of extruded profiles rather than welded plates. This approach provides a flat surface, avoiding the need for floor screed, using instead a floating floor which itself saves 35 - 40 Kg/m^2.

On a more detailed level, the design has considered a wide range of alternative equipment, ranging from ducts and hangars in aluminum, firerated doors and windows to electrical cable ladders already applied with considerable success on the Oseberg A. Overall structural weight saving for the prototype module is 50% of the original weight in steel. Once all ancillaries are added, including the helideck, walkways and fire insulation, the final module lift weight will exhibit a 35% saving. **(6)**

The performance of aluminum alloys in fires is of particular concern and in this respect they are not likely to be considered suitable for applications in all areas, particularly near hydrocarbon sources. Since aluminum has a lower melting point than steel (650 - 660°C compared to 1530°C for steel) the introduction of external fire protection may be required to adhere to the maximum allowable temperature of about 200°C in any load carrying aluminum structure.

The unique possibilities of aluminum with respect to formability should be utilized to minimize the welding of aluminum structures, and for positioning the welds outside stressed areas. Should the latter not be possible, then the loss of strength incurred from welding aluminum can be compensated for by increasing the material thickness in the over stressed areas.

Two other problems associated with the use of aluminum are galvanic corrosion and aluminothermic reactions. The former is easily controlled using insulating material located at contact points between aluminum and steel. The latter is somewhat more difficult to control, although the risk of such a reaction occurring is minimal in comparison with other potential sources of explosion. Nonetheless, it may be sufficient to eliminate the use of aluminum in areas where volatile gases are present.

High Strength Steels (HSS) are steels with yield strengths above 400 MPa and offer the potential for considerable weight savings over mild steels in offshore applications. This type of material was first used on the Magnus Field platform development and has recently been used on British Petroleum's Norwegian sector Gyda Platform.

Major advantages of HSS include a reduction in weld volume with decreasing plate thickness leading to savings in construction time; reduced requirements for plate thickness and stiffener spacing; and sufficient weight reduction to lessen the effects of environmental loading. **(7)** It is estimated that the use of HSS for primary load bearing structural members would yield reductions between 9% and 14% (for Grade 55F and RQT701 HSS) compared to grade 50D steels currently in use. However, the associated cost savings for HSS are less encouraging.

Topside applications for HSS include helideck, transition pieces between concrete shafts and lower deck, extra hard plates to shield against explosions and dropped objects, and protective walls.

Weight reduction through the use of aluminum and HSS can be enhanced by using the so called **Stressed Skin** design. The design enables wall panels to serve as structural elements thereby contributing to the global strength of the module. This allows the number of highly stressed areas to be kept to a minimum since forces acting on the structure will be distributed over the length of the structural members. The design assumes that plate panels resist shear forces only and that normal forces are carried by vertical columns at panel edges such as wall to floor supports, and where internal walls meet external longitudinal walls. Vertical columns can be built up of welded plates to box elements with a typical thickness of 20 mm. The stressed skin design as a structural system offers the following advantages:

- reduced fabrication costs due to high repetition of structural elements,
- reduced weight since structural elements required for global strength can be utilized for shielding purposes,
- increased adaptation to different layout needs due to elimination of diagonal bracings,
- reduced space needed for the load carrying structure.

The stressed skin design offers significant weight advantages but is mainly suited to living quarter modules where the number of penetrations are considerably less than those on other modules.

Fiber Reinforced Plastics are a cost effective material, especially with respect to low weight and corrosion resistance, and can be substituted for steel components in several areas of topsides design. FRP are particularly suitable as an alternative material for some piping systems which, when replacing existing systems, can reduce both weight and cost by about 70%. **(8)** Aside from its use in piping systems, FRP can be used in storage tanks, casings, corrosion protection, lifeboats, housings and shelters, cable ladders and trays, and internal accommodation cladding.

The main concern over FRP is its fire performance, mainly in terms of smoke and toxic emissions since structural integrity is maintained due to the low thermal conductivity of FRP. Other areas of concern are the effectiveness of fabrication, and joining and repair techniques.

FRP have yet to gain wide acceptance in the offshore industry although their potential weight and cost savings are apparent.

Larger modules: With the advent of a new generation of heavy lift vessels the possibility of constructing "super modules" in excess of 4000 tonnes was realized. By planning modules such that complete process and/or utility systems are installed within a single module, hook-up requirements between modules, and between modules and MSF are considerably reduced.

In studies conducted by Norwegian Petroleum Consultants for the A/S Norske Shell Troll field development, estimated percentage reductions (by weight) in hook-up requirements in major topside areas are as follows:

- Piping	53%
- HVAC	30%
- Structural	10%
- Mechanical	40%

In addition, 10% savings by length are achieved in the areas of electrical and instrumentation hook-up. **(9)**

The use of large modules for this development as opposed to a base case design (medium sized modules) is illustrated in Figure 2. By incorporating major items of equipment within larger modules, the number of topside modules was reduced from 22 to 10. The two base case power generation modules were combined to form a single module containing all main and emergency power generation facilities, complete with all switchgear, transformers and power generation controls. All drilling support facilities and workshops were combined into one module as were the two base case wellhead modules containing all the production and test manifolds associated with each drill shaft. Gas processing and process support facilities for the base case are distributed within eleven module and weather deck areas. These process facilities are now housed within three larger modules as follows:

- Module M-04 contains the complete gas separation, dehydration and dew point control facilities and glycol regeneration units,

- Module M-05 contains the complete flash gas compression and fuel gas systems,

- Module M-06 contains the gas manifolds, pipeline gas compression, gas metering and gas export facilities.

A comparison between base case modules and super modules is given in Table 1 and the weights for the latter are summarized in Table 2.

Further weight savings can be realized within super modules by optimizing equipment layout and fine tuning the structural design by using lightweight materials, etc.

Integrated Decks: The use of an integrated deck structure requires a considerable amount of cooperation between the structural steel designers and the process/utility installation designers. The main advantage of an integrated deck is the substantial weight savings afforded by a reduction in the amount of structural steel required which, in a modularized deck, serves only to maintain the structural integrity of the modules during load out and lifting.

Integrated decks have been used in such field developments as Phillips Petroleum's Maureen Development, Conoco's Hutton TLP and more recently in the proposed design of Norsk Hydro's Troll East field development.

The first of these developments used an integrated deck concept known as HIDECK, developed by Brown & Root Inc., George Wimpey and Company Ltd., and Brown and Root - Wimpey Highlands Fabricators Ltd., and offers many advantages over the traditional modular deck concept. In particular, the structural steel requirements in decks are reduced by 60%, and piping and electrical cabling runs are considerably reduced, both leading to an overall reduction in topside weight. HIDECK, which is built and transported in one piece, utilizes a "balanced stress" design to reduce the percentage of steel required to approximately 30 - 40% of the total deck weight. This concept makes the most of the principal steel work in that it takes stresses near to its allowable stress during both transportation and operation of the deck. It is estimated that the HIDECK concept would save approximately 9,000 tonnes of steel if it were used to replace a conventional modular deck structure weighing 15,000 tonnes and carrying equipment weighing 10,000 tonnes. **(10)**

The open truss concept of the HIDECK permits a more optimum layout of facilities, and equipment can be installed in an almost random fashion. Skid packages are used for equipment on the lower and mezzanine decks, which contain all the process and utility equipment, while modules are used for upper deck packages, including living quarters , drilling rig and generators. A total of 29 skid packages and 10 modules are used on the Maureen platform (ref. Figure 3).

To minimize the weight on the Hutton TLP it was necessary to locate related equipment in the same area, thus reducing piping, cabling and ducting runs. In addition, minimum deck structural weight was achieved by defining the position of the equipment and the bulkhead penetration locations before doing the detailed design work. Consideration of these factors resulted in the functionalized layouts shown in Figures 4a through 4c, illustrating weather deck, mezzanine level and main deck plot plans. Three important features can be noted from these layouts:

- The vertical arrangement of the power generation, transforming, and distribution and control area minimized the number of cable runs while maximizing the efficiency of electrical installation work,

- The size of the hazardous area was minimized and located entirely on the south half of the platform,
- The accommodation modules are cantilevered to provide the necessary lever arm to offset the weight of the drilling derrick , sub structure and well riser tensioners.

As was the case with the HIDECK concept, several modules were required for the Hutton TLP including accommodation facilities, helideck, drill rig and derrick, and flare tower. **(11)**

The weight savings afforded by the use of an integrated deck concept are well illustrated in the above examples. However, there are several "knock on" effects of utilizing an integrated deck which deserve mention:

1. Simultaneous fabrication and hook-up operations can continue once the primary structural framework has been erected,
2. A certain amount of onshore commissioning can take place, thus eliminating some of the more expensive offshore commissioning,
3. The deck structure can be fabricated in sections at more than one yard and brought together at a single site for final assembly. This particular concept is proposed for Norsk Hydro's Troll East field development. **(12)**

Further weight reductions within the integrated deck concept can be gained by optimising equipment layout within the deck, using lightweight materials, and incorporating innovative equipment technology to be discussed in the following section.

INNOVATIVE EQUIPMENT TECHNOLOGY

The reduced oil prices of the past few years have done little to stymie the research and development effort in the offshore oil industry. In fact, they have probably bolstered the search for new cost effective, low weight equipment solutions.

A major stumbling block in the introduction of new technologies offshore has always been convincing platform operators of its reliability. Vendors must satisfy the "age old" questions of - Is it proven technology? Does it have a proven offshore track record?

Some of the more promising and interesting weight conscious equipment developments of the past few years have emerged in the following areas (ref. Figure 5):

Produced water treatment: Hydrocyclone separators offer considerable weight and space savings over traditional equipment used for oily-water clean up such as flotation cells and plate coalescers. These vessels operate on the principal of centrifugal separation of a dispersed, low density phase from a continuous, higher density phase (ref. Figure 6).

The 4 in 1 35 mm "Vortoil" hydrocyclone package installed on Conoco's Murchison platform, for example, is about one-fifth the size and one-tenth the operating weight of a comparable flotation cell system. **(13)**

Seawater injection: Conventional systems used to treat injection water offshore consist of heavy sand or mixed media filters and large vacuum or stripping gas deaerator towers. This equipment occupies a great deal of space and imposes large weight penalties.

A 50,000 b/d seawater demonstration plant developed by Conoco Norway in conjunction with Norsk Energi (i.e. the "Seaject" system) could cut weight by as much as 70% and space by 30 - 40% over conventional systems. The dramatic weight and space savings are attributable to the use of lightweight, back-washable polypropylene cartridge filters and catalytic deoxygenation equipment. **(14)**

Hydro Minox a.s., a subsidary of Norsk Hydro, has also developed a super efficient catalytic deoxygenation system which is 25 - 50% of the weight of conventional units.

Pumping: Product lubricated pumps utilize bearings lubricated by the liquid being pumped. By elimination of the separate oil lubrication system, reductions in length up to 45% and weight by 5 tonnes for a typical 2 MW seawater injection unit have been claimed by the manufacturer. **(15)**

Hydraulic mud pumps offer weight reductions up to 75% compared to conventional DC-driven units.

Heat transfer: Compared to conventional shell and tube heat exchangers, plate-fin designs have large heat transfer areas packed into compact, lightweight units which can handle multiple product streams. Operating efficiency is high, resulting in very low temperature differences between streams.

Dramatic weight and space reductions are possible compared with shell and tube exchangers. Used as aftercoolers for a 25,000 hp gas compressor, for example, plate-fin exchangers would weigh 9 tonnes and occupy 15 m^2, compared with 90 tonnes and 35 m^2 for shell and tube exchangers. **(16)**

Platform air supply: A weight optimization program developed by Aker Engineering has identified a means of eliminating air compression equipment. Plant and instrument compressed air requirements can be supplied from gas turbine bleed air. **(17)**

Multi-phase metering and transport: Multi-phase initiatives have emerged from the drive to reduce the costs and complexity of subsea developments.

Development of multi-phase meters (mpm) which can accurately measure the oil-water-gas flow in a well could mean eventual elimination of topside test separators and metering equipment. The world's first subsea three-phase meter is due to be tested at Texaco's Tartan field this year.

On the other side of the coin, subsea multi-phase pumps (mpp) could revolutionize the offshore industry by eliminating the need to have production platforms adjacent to wellheads altogether. Oil and gas could be transported directly from the seabed to onshore production facilities.

CONCLUSIONS

It is evident that significant weight savings are possible on production platform topsides through effective design and careful planning. New materials, innovative equipment technology and space optimization all contribute to a lighter, less expensive petroleum production facility. The bottom line in all these approaches is, of course, cost efficiency. The extra capital investment required for many of these new materials, equipment and facilities must justify the weight, space, and ultimate cost savings.

ACKNOWLEDGEMENTS

The authors would like to acknowledge the contributions of Mr. K. Kennedy who, while during his employ at NorTek, performed some of the initial ground work for this paper.

WEIGHT SAVING EQUIPMENT OPTIONS

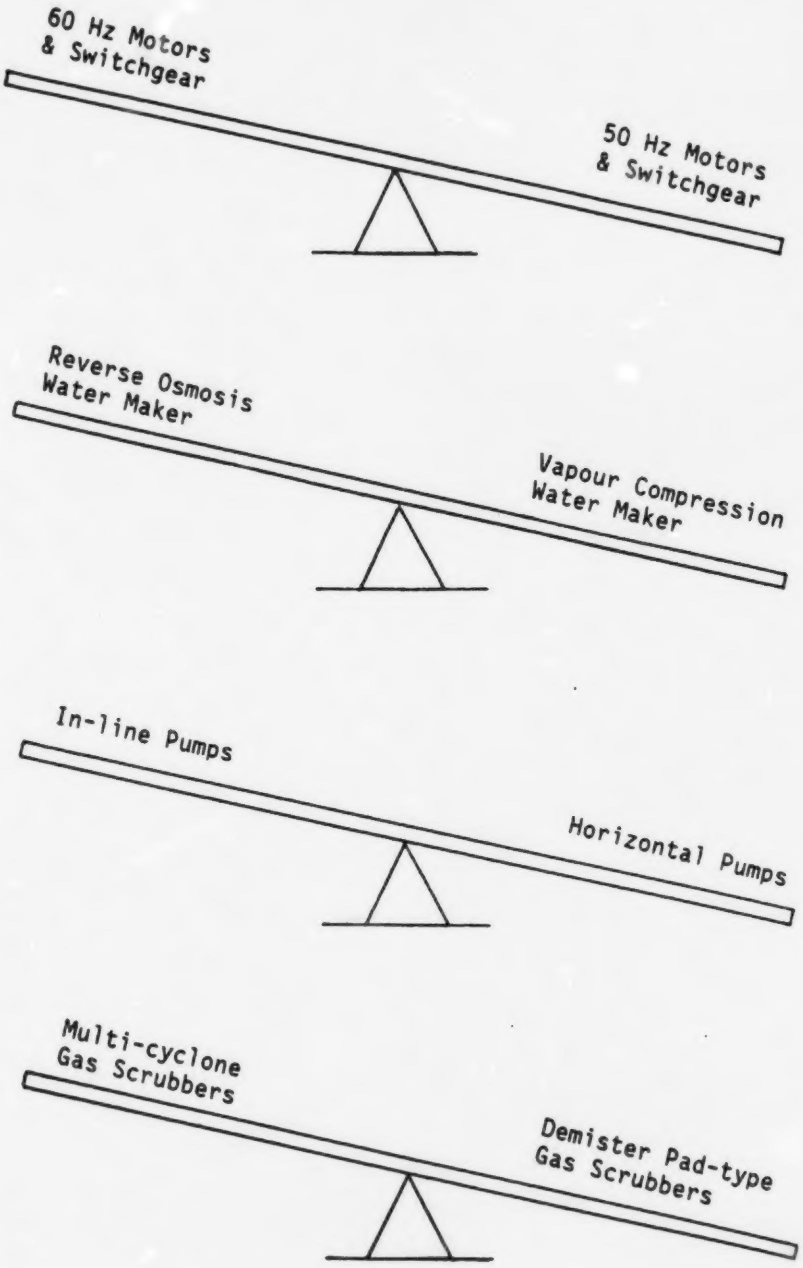
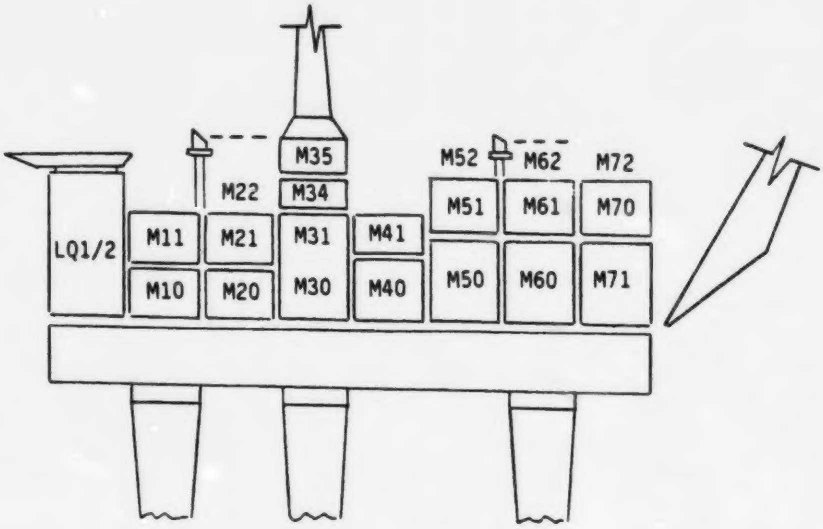
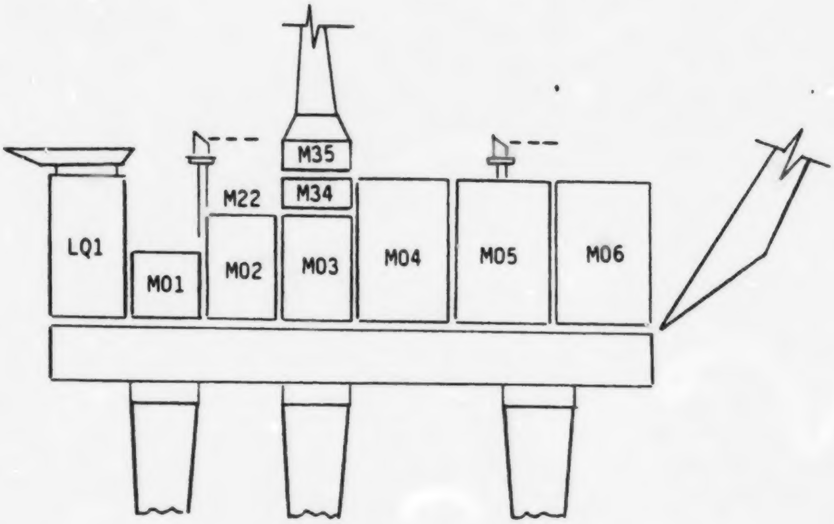

60 Hz Motors
& Switchgear
50 Hz Motors
& Switchgear
Reverse Osmosis
Water Maker
Vapour Compression
Water Maker
In-line Pumps
Horizontal Pumps
Multi-cyclone
Gas Scrubbers
Demister Pad-type
Gas Scrubbers

FIGURE 1


M35
M52
M62
M72
M22
M34
M51
M61
M70
LQ1/2
M11
M21
M31
M41
M10
M20
M30
M40
M50
M60
M71

BASE CASE


M35
M22
M34
LQ1
M01
M02
M03
M04
M05
M06

LARGE MODULES

FIGURE 2

Source: NPC

TABLE 1
COMBINATION OF BASE CASE MODULES TO FORM LARGE CASE MODULES

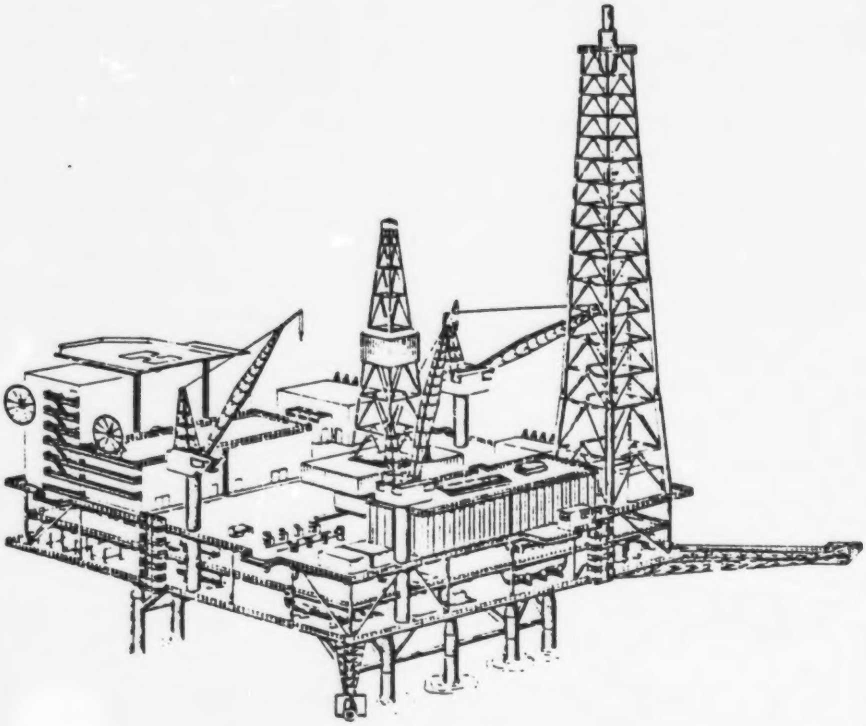
BASE CASE MODULES		LARGE CASE MODULES	
MODULE NUMBER	DESCRIPTION	MODULE NUMBER	DESCRIPTION
LQ-1, LQ-2	Living Quarters	LQ-1	Living Quarters
M-10, 11	Power Modules	M-01	Power Module
M-20, 21	Drilling/Utility	M-02	Drilling/Utility
M-30, 31	Wellhead Modules	M-03	Wellhead Module
M-40, 41, 50	Gas Conditioning Modules	M-04	Gas Conditioning Module
M-51, 52, 60	Flash Gas Compression Modules	M-05	Flash Gas Compression Module
M-61, 62, 70 M-71, 72	Pipeline Gas Compression Modules	M-06	Pipeline Gas Compression Module

Source: NPC

TABLE 2
WEIGHTS OF LARGE MODULES

MODULE NUMBER	MODULE DESCRIPTION	MODULE WEIGHT (tonnes)		
		DRY	OPERATING	LIFT
LQ-1	Living Quarters	3540	3584	3660
M-01	Power Generation	2266	2330	2386
M-02	Utility/Drilling	2615	3333	2700
M-03	Wellhead	4338	6094	4434
M-04	Gas Conditioning	8507	8996	8610
M-05	Flash Gas Compression	4019	4294	4139
M-06	Pipeline Gas Compression	6584	6938	6704

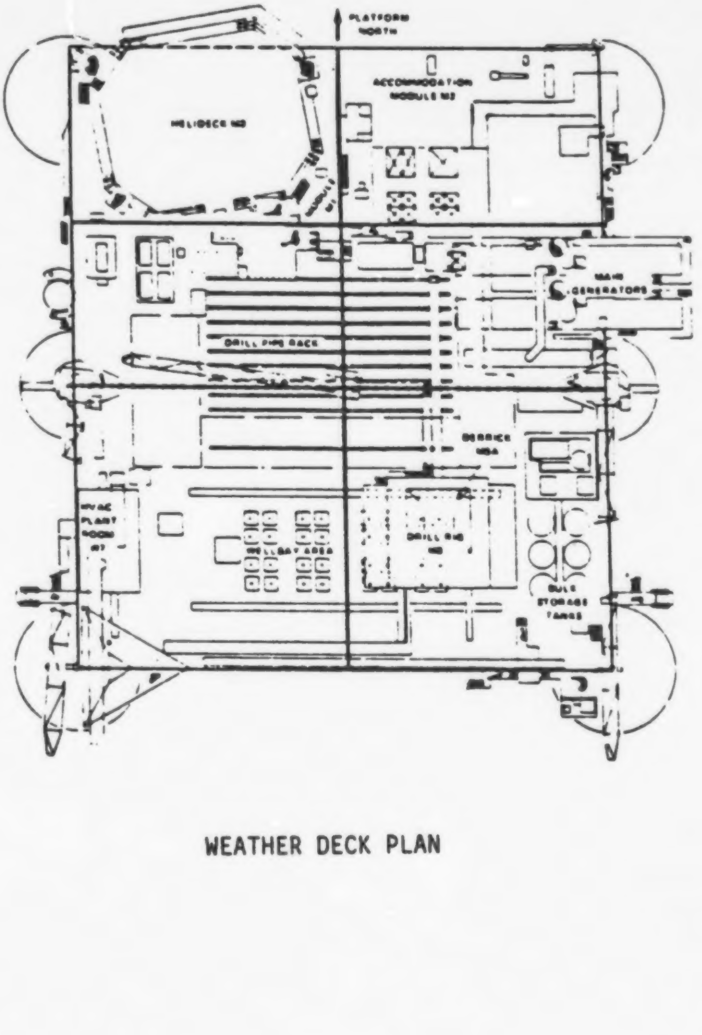
Source: NPC



MAUREEN PLATFORM HIDECK

FIGURE 3

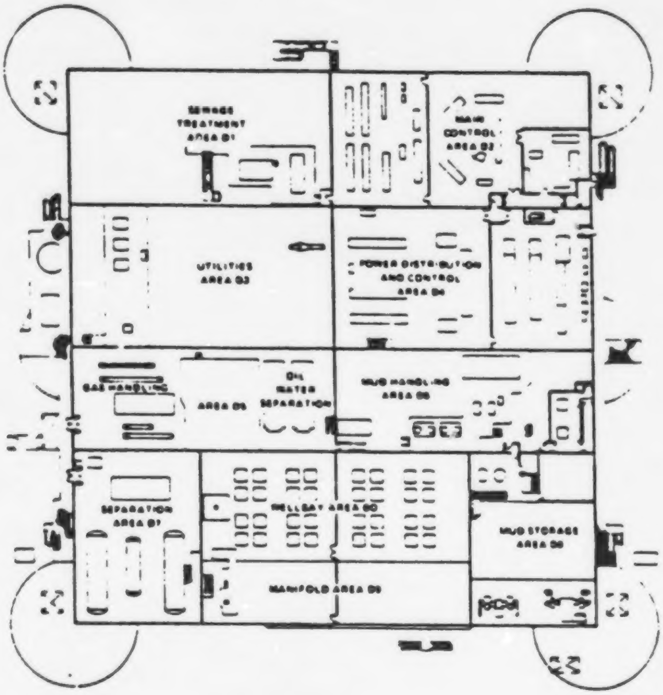
Source: OTC 3879


PLATFORM NORTH
HELIDECK
ACCOMMODATION MODULE
MAIN GENERATORS
DRILL PIPE RACK
DERRICK
HVAC PLANT ROOM
WELLBAY AREA
DRILL RIG
BULK STORAGE TANKS

WEATHER DECK PLAN

FIGURE 4a

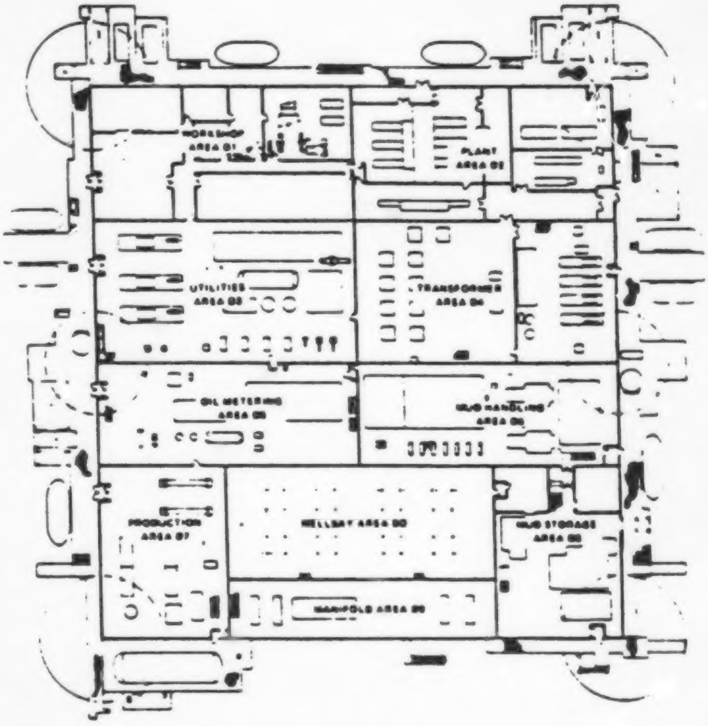
Source: OTC 4912


SEWAGE TREATMENT AREA 01
MAIN CONTROL AREA 02
UTILITIES AREA 03
POWER DISTRIBUTION AND CONTROL AREA 04
GAS HANDLING
AREA 05
OIL WATER SEPARATION
MUD HANDLING AREA 06
SEPARATION AREA 07
WELLBAY AREA 08
MUD STORAGE AREA 06
MANIFOLD AREA 09

MEZZANINE DECK PLAN

FIGURE 4b

Source: OTC 4912


WORKSHOP AREA 01
PLANT AREA 02
UTILITIES AREA 03
TRANSFORMER AREA 04
OIL METERING AREA 05
MUD HANDLING AREA 06
PRODUCTION AREA 07
WELLBAY AREA
MUD STORAGE AREA
MANIFOLD AREA

MAIN DECK PLAN

FIGURE 4c

Source: OTC 4912

WEIGHT SAVING INNOVATIVE EQUIPMENT TECHNOLOGIES

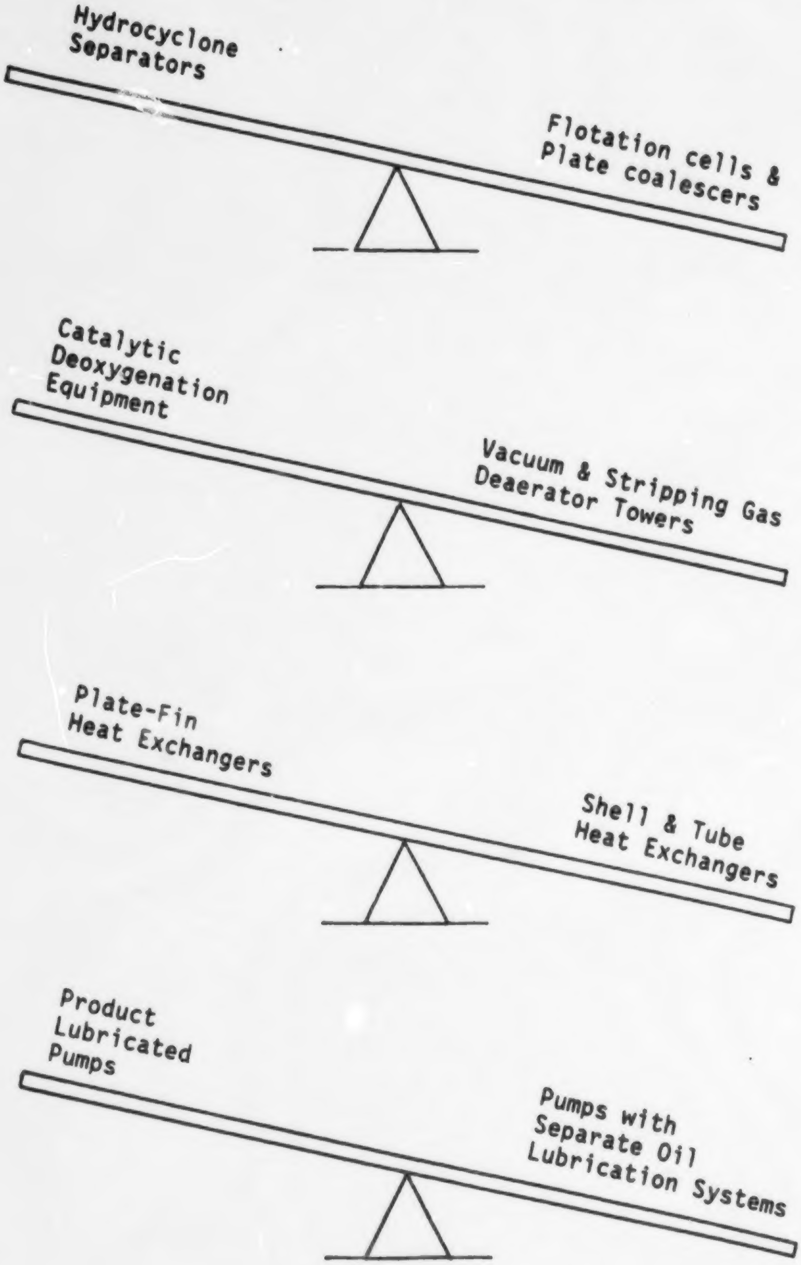
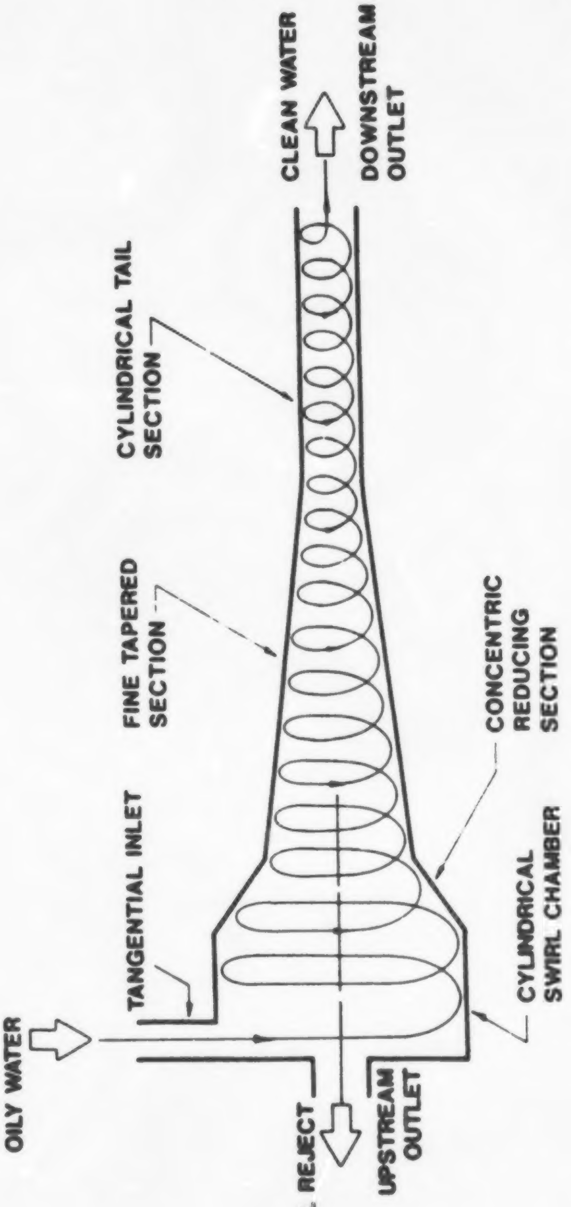

Hydrocyclone Separators
Flotation cells & Plate coalescers
Catalytic Deoxygenation Equipment
Vacuum & Stripping Gas Deaerator Towers
Plate-Fin Heat Exchangers
Shell & Tube Heat Exchangers
Product Lubricated Pumps
Pumps with Separate Oil Lubrication Systems

FIGURE 5


OILY WATER
OIL REJECT
UPSTREAM OUTLET
TANGENTIAL INLET
CYLINDRICAL SWIRL CHAMBER
FINE TAPERED SECTION
CONCENTRIC REDUCING SECTION
CYLINDRICAL TAIL SECTION
CLEAN WATER
DOWNSTREAM OUTLET

HYDROCYCLONE SEPARATOR

Source: BWN Vortoil

FIGURE 6

REFERENCES

1. The Oil and Gas Journal, "Optimize Platforms During Planning Design Stages", September 1977.
2. Offshore Technology Conference, "Topsides Weight Reduction Design Techniques for Offshore Platforms - OTC 5257", 1986.
3. The Oil and Gas Journal, "Design Options Can Save Space and Weight on Offshore Platforms", July 1979.
4. Offshore Engineer, "Weight Conscious Drilling Packages", September 1987.
5. Offshore Engineer, "Oseberg brings Aluminum nearer Industry Acceptance", September 1987.
6. Offshore Engineer, "Full Scale Snorre first for Aluminum", November 1988.
7. Ocean Industry, "High Strength Steels gaining Applications", March 1989.
8. Offshore Engineer, "Topside Savings: Contenders for the Lightweight Title", September 1987.
9. Norwegian Petroleum Consultants A.S., "Condeep SP Large Module Layout Study - Troll Field Engineering Studies", 1985.
10. Offshore Technology Conference, "A New Integrated Deck Concept - OTC 3879", 1980.
11. Offshore Technology Conference, "Hutton TLP Integrated Deck - OTC 4912", 1985.
12. Norwegian Petroleum Consultants A.S., "Norsk Hydro - Troll East Development Project, Integrated Deck Topsides placed on a Fixed GBS Platform", 1984.
13. Offshore Technology Conference, "Hydrocyclones: A Solution to Produced Water Treatment - OTC 5595", 1987.
14. Offshore Engineer, "Water Injection - Catalyst For Change", June 1988.
15. Offshore Engineer, "Topside Weight Savings From Product Lubricated Pumps", February 1988.

16. Offshore Engineer, "**Compact Exchangers Shaping Up For Success**", July 1987.

17. Ocean Industry, "**Topsides Optimization Cuts Development Costs**", April 1989.

SPEAKER : **ARILD THORSRUD**

COMPANY : **AKER DRILLING A/S**

LOCATION : **NORWAY**

TOPIC : **DRILLING MODULE WEIGHT REDUCTION**

BIOGRAPHY: Mr. Thorsrud graduated from the Royal Norwegian Naval Academy in 1972. He spent four years in submarines before changing to offshore drilling on floaters. Then he went onshore and has, for the last seven years, held management positions in floater and platform drilling operations, well services and technology.

INTRODUCTION

This presentation is meant to outline concepts of how to reduce weight of drilling facilities and what can be achieved by optimisation.

Since 1973, when the first drilling modules were installed in the North Sea weights of new drilling modules have increased steadily. (ref. fig. 1)

However there are a few exceptions.

In search of the optimal low weight and cost effective solution, as can be seen from fig. 1, two exceptions from the trend have been designed. In addition, several studies have been completed, which have resulted in weight saving changes to other projects.

The issue of weight reduction has played a major part in reducing the cost. It has been absolutely necessary to make late North Sea project economically feasible in light of the reduced oil and gas prices.

APPROACH TO WEIGHT SAVING

The main criteria for being able to make an optimal drilling design and save weight is that the designer has the knowledge of whats required at each step of the planned drilling operation.

Overspecification of capacities based on theoretical and impractical worst cases is not uncommon. Lack of understanding is covered by large capacities and "nice to have" philosophies and insurances.

However, in many cases poorly defined design bases is causing unnecessary large facilities. This is usually caused by tight development schedules, where design has to start before evaluation of drilling programs and mud types to be used, etc. have been properly done.
For example if no conclusion is reached, whether to use oil or water based mud, the design then starts considering worst case. When the conclusion is made, the project has progressed too far, with respect to schedules, to allow for any redesign.
A redesign would normally have influence on both drilling facilities and the entire platform.

If time and schedules allows, it is of vital importance that a thorough evaluation of the drilling programme and design basis is done before the design phase starts. If the design basis is still subject to discussion at the beginning of the project a realistic base case should be selected and should avoid covering several options.

A realistic design basis is normally considered to be worst case (worst case planned well, worst case resupply situation, weather conditions etc.).

This solution may lead to over specification, excess weight and cost.

If this worst case can be expected to occur during drilling of 1 or 2 of e.g. 20 wells, different operation procedures, temporary equipment, different supply schedule or standby supply boat could be used while drilling the extreme well(s).
The design basis will then be in accordance with an optimal worst case.

The drilling of the extreme wells may take some more time, but experience has shown that single extreme wells can be drilled in an efficient and safe manner with relatively simple means and by adjusting operation and supply procedures.

The philosophy of a "optimal worst case" can also be used for individual systems or equipment. For instance, when sizing derrick and substructure for pulling 70-80 percent of worst case casing yield, considering full setbacks and high wind velocities.

It is only a matter of operation procedures to e.g. set limits related to wind velocity when maximum load is to be applied. Equipment that is used only during short phases of the drilling operations should be based on use of temporary equipment, e.g. completion equipment.

The overall goal when defining design basis and preparing system design philosophies should be to aim for a simple, cost effective and safe systems covering the normally expected drilling operations. Special requirement and "nice to have philosophies" should be justified by comparing operation cost reduction/benefits with total additional system cost (including engineering, fabrication, installation, hook-up, commissioning, operation, maintenance, and preservations).

The drilling design has to be as compact and space efficient as possible. Weight, volume and cost are directly proportional to each other. Another advantage of a compact design is that it requires less people to run.

To summarize:

* Knowhow
* Defined design basis
* Design basis = normal worst case
* Flexibility for temporary add on equipment
* Simple and effective systems.

ACHIEVEMENTS

From Fig. 1, Fig. 2, Fig. 3 and Fig. 4 it can be seen there are two exceptions from the development trend in the Norwegian North Sea of newer date. It is the 2/4-K Ekofisk drilling facilities and the planned Troll drilling facilities.

The Ekofisk 2/4-K was initially planned in 1983 with complete drilling facilities of approx. 5000 mT dry weight.
It was at that time suggested that a lot of weight and cost could be saved by rebuilding some existing modules from the Edda platform and build some new modules.
PPCON accepted this suggestion, in spite of the fact that they had already spent several million NOK developing another design.

Upon installation of the facilities the weight was reduced to 3350 mT. In comparison, the Gullfaks 'A' drilling facilities, installed at the same time, are 2.2 times heavier and 2.5 times more expensive. Drilling depths and operation for the two are very similar. Both are designed for oil base mud, with the same type cutting cleaning system, both having modern pipe handling systems and tope drive.
If the same philosophy had been applied for the two designs, there is no reason why the weight difference is not within 500 mT.

Note also that the compact 2/4-K is operated with 28 men on two shifts, while the Gullfaks 'A' is operated with 38 men on two shifts.

Of more recent projects, the Troll conceptual engineering should be mentioned. Still in a conceptual pre-engineering phase, several options are still under discussion. However, earlier drilling facilities design was estimated to approx. 6000 mT and is at present estimated to approx. 4000 mT. This was a very thorough evaluation of the systems and capacities, and a total redesign of the modules.

To illustrate typical changes, the following table gives a comparison between old and new capacities.

ITEM	NEW CAPACITIES	OLD CAPACITIES
- Derrick hook load	227 mT	454 mT
- Drawworks	1500 hp	2000 hp
- Mud pumps	2 x 1600 hp	2 x 1600 hp
- Mud tanks and mud storage	400 m3	650 m3
- Bulk barite	150 m3	280 m3
- Bulk cement	150 m3	210 m3

The new design allowed for a one floor mud module and released 2000 m3 platform space for other purposes.

In parallel to the development of a conventional type derrick and substructure, an alternative study was performed together with Deutag Drilling, to investigate the possibility to use an automated "Single Rig".

The "Single Rig" is a further development of the Walker Near rigs, designed to handle 5 inch, range 3 drillpipe, 9 1/2 inch drill collars, all casing sizes and 26 inch conductors.
In addition a control system for automatic handling have been developed. The signle rig is based on tripping by breaking down/building up single joints. (ref. Fig. 5)
The study concludes that weight reduction of 550 mT and cost reduction of approx. 15 percent of total cost, is possible.

At present, even further weight reducing changes are evaluated based on a revised drilling programme, and by making the facilities partly removable by the platform cranes.

Another recent project in the Norwegian North Sea is the Sleipner project. The platform concept studies were started several years back in the "prosperous times" and it is still a large and heavy design.

When we were asked by Statoil Operations Department to investigate possibilities for reducing size and weight of the drilling modules, the project had already started detail designing.
The findings from Our study concluded that a reduction of 1800 mT to the traditional drilling modules was possible. In addition, another 1000 mT could be saved by reducing the size of the wellhead module.

The reduction of the wellhead module was later verified by the Detail Design Contractor and Statoil Operations Department did an inhouse exercise, verifying the reduction of the other drilling modules. It is still evaluated if there is time left to do the necessary changes, to achieve this weight and cost reduction.
The main problems are that a lot of the material purchase packages are already out for bid, and changes to the scope of detail engineering contract will be required.

RE-USE

During evaluation of the Sleipner drilling modules the idea of reusing the drilling facilities on other platforms, e.g. Troll, appeared again. Both the Sleipner and the Troll fields are gas producing, where very little workover activities are expected.

The obvious advantage of reuse is a division of the investments per platform for the drilling facilities of 2 (or more), whether owned by a drilling contractor or the operator.
If the facilities are owned by the drilling contractor, the actual investment could be postponed until drilling and production have started.

This idea was the basis for the approach to the Ekofisk 2/4-K drilling facilities design where the existing Edda modules where rebuilt. This approach gave a significant contribution to reducing cost regardless of savings, made from the lighter and more compact concept.

For the Sleipner concept, estimates showed that more than 1 billion NOK could be saved by implementing the weight savings and re-use of the facilities on the Troll project only.
These savings were only related to the Sleipner project and in addition, substantial savings could be achieved for the Troll project.

CONCLUSION

To be able to achieve the optimal solution in respect of weight/volume/cost, the key factors are:

- Schedules allowing for establisment of a realistic drilling programme.
- Properly defined design basis and the knowledge of how to define the normal design cases.
- Simple, flexible and effective system design, based on sound knowledge of what's required for the specific tasks.

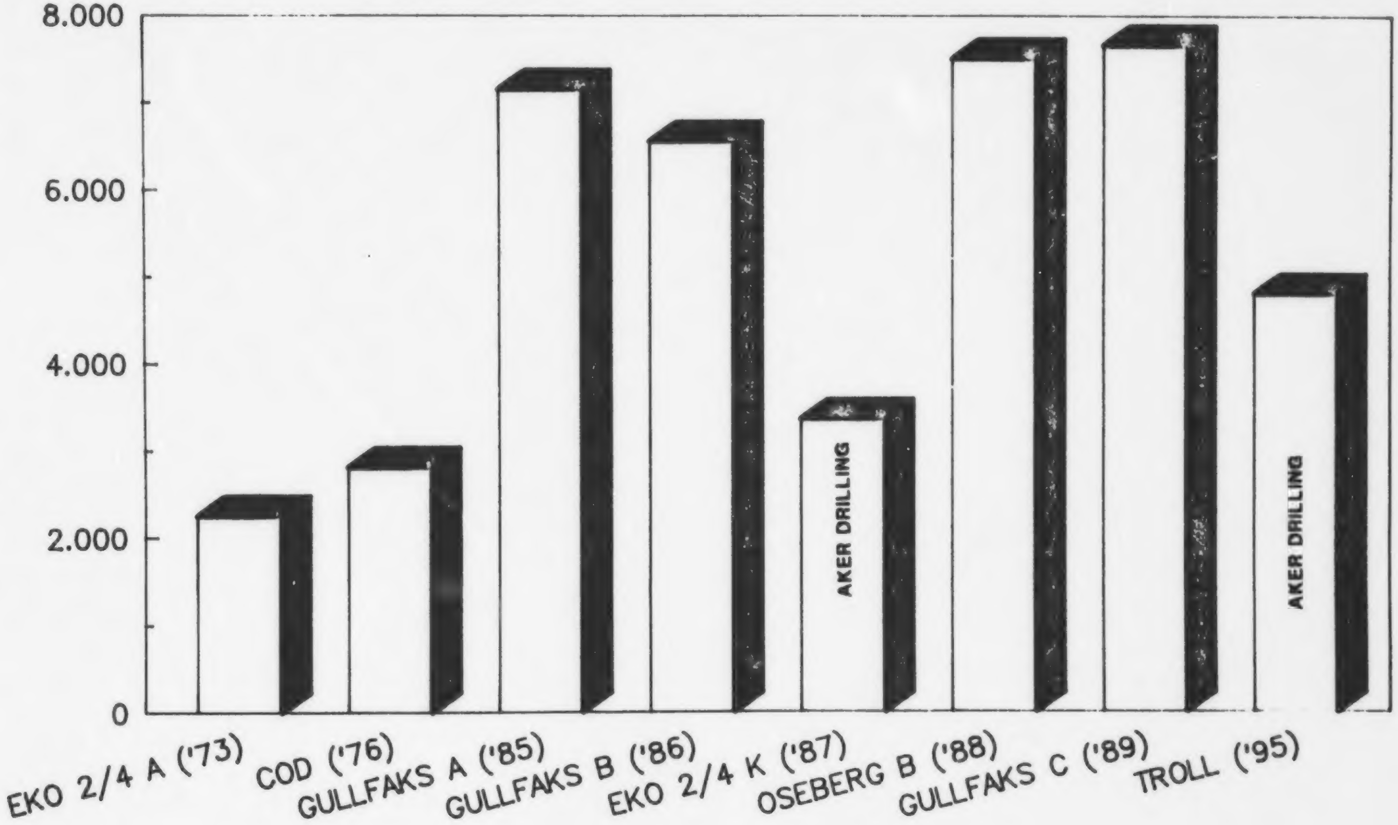
Without introducing any new technology it is possible to reduce weight in the oder of 30 percent, compared to other approaches.

Even more can be achieved if effort is put into developing new efficient equipment. Additional cost saving will be achieved by full or partly re-use of both equipment and modules.

WEIGHT COMPARISON OF EIGHT DRILLING MODULES

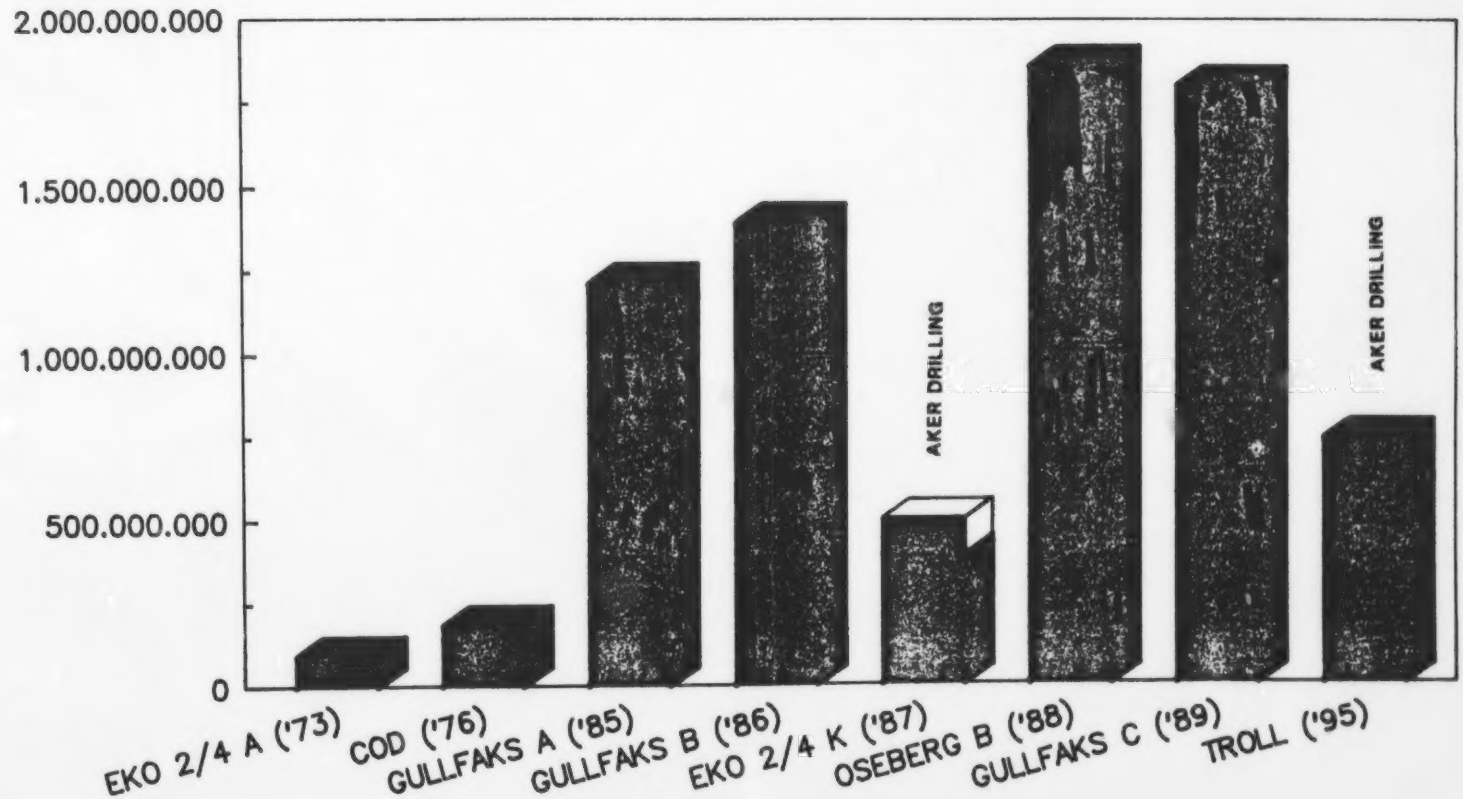
(WEIGHT IN TONNES)

FIG 1



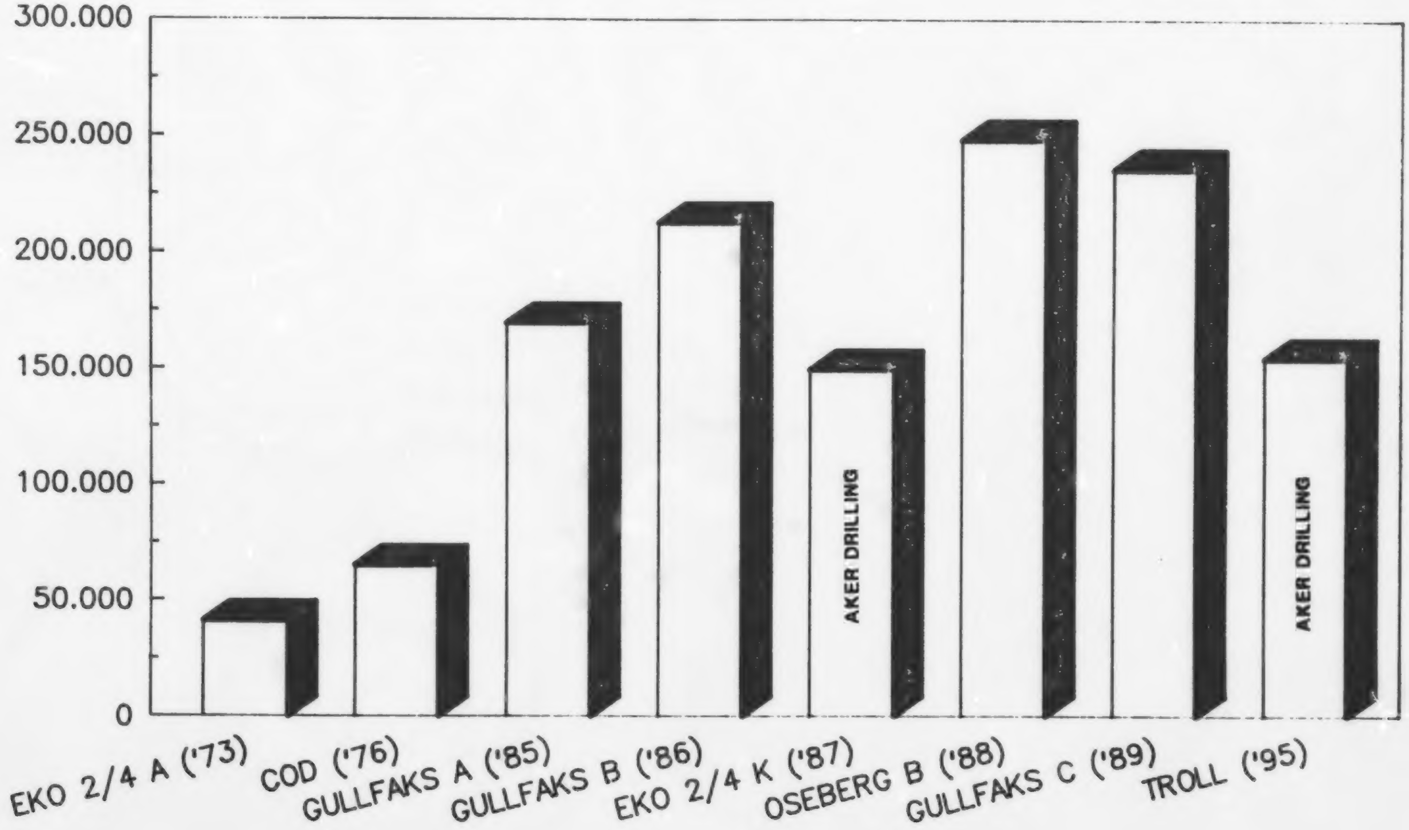
COST (NOK)

FIG 2



COST/WEIGHT RATIO
(NOK/TONNES)

FIG 3



WEIGHT/VOLUME RATIO
(TONNES/CU.METER)

FIG 4

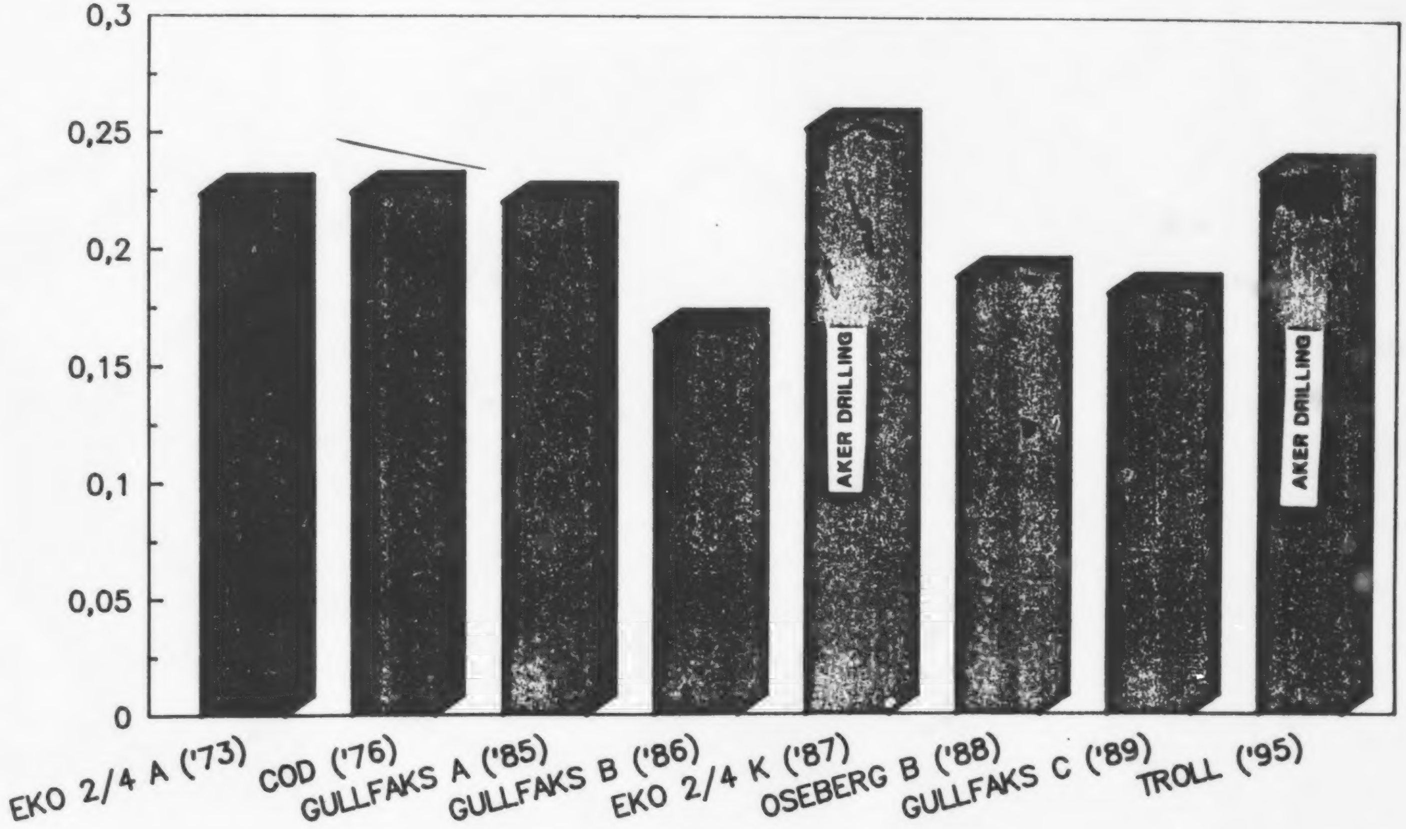
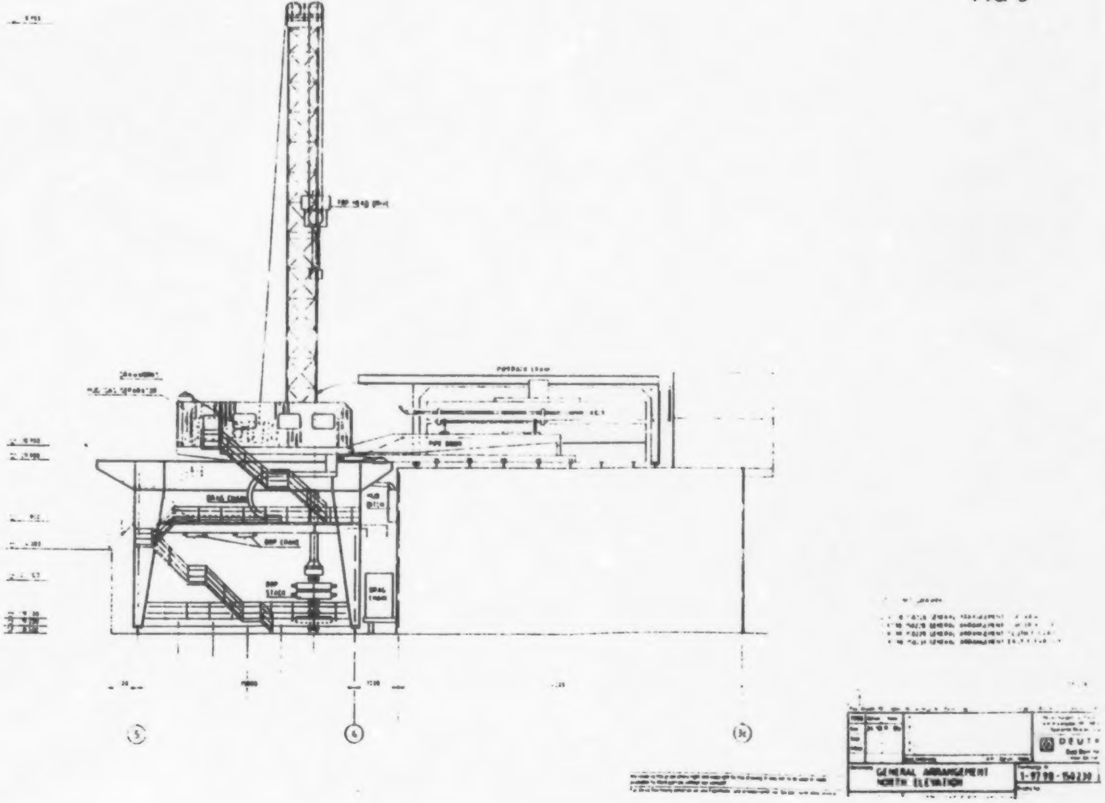


FIG 5


GENERAL ARRANGEMENT
NORTH ELEVATION
DEUT

SPEAKER : **ARNE LINDEKLEIV**

COMPANY : **MARITIME HYDRAULICS A/S**

LOCATION : **NORWAY**

TOPIC : **WEIGHT SAVINGS IN DRILLING FACILITIES**

BIOGRAPHY: Mr. Lindekleiv is presently working with Maritime Hydraulics A/S. Before this he worked for four years with Norwegian Rig Consultants A/S as Mechanical Lead Engineer. He also worked for five years as a driller in the North Sea and the Far East.

As drilling for oil and gas has moved into deeper waters, the need for lighter equipment and modules has arised. Despite this need, the drilling modules have grown heavier and heavier.

This overhead shows how the ratio between the weight of the drilling and topside modules has changed over the years. The green columns are representing the weight of the top side modules while the red columns are representing the drilling modules. This confirms what I said about weight increase.

The figures are not 100 % correct as the various topside concepts are not identical. The trend, however, is quite clear.

This weight increase has no relation to the water depth, but can it be linked to oil production capacity ?

From this overhead we can see the same trend as for the other overhead. The ratio is changing for the worse. The drilling modules get heavier.

There are many reasons for this weight increase, but the most significant ones are:

- Increased demand for automation and mechanization of equipment.

- Increased demand for redundancy and back-up systems.

We have done something to stop this trend. We have looked further into the drilling modules in order to save weight and still fullfill the requirements for mechanization, automation and redundancy.

When starting the multi million dollar development program, the main objectives were listed as follows:

- We should be able to offer the new platform builders a complete integrated drilling equipment package, taking the full benefits of the latest available technology. The package was to contain machinery for hoisting, rotation, pipehandling and mud pumping
- Reducing the weight of the equipment in a "standard" drilling package by more than 100 tonnes. (Standard package: Three 1600 Hp DC- powered Mud pumps, independent DC-powered 49.5 in. rotary table, 3000 HP DC-el. Drawworks with "elmago" brake, DC-el. 1000 HP top drive, and SCR-system.)
- To have a central, common power unit to serve all the heavy equipment components for mud pumping, hoisting and rotation. This gives a very flexible power distribution system with a high degree of redundancy.
- The power unit to be driven by any kind of motor running at constant speed.
- Centralized cooling of all the motors for power swivel, rotary table, mud pumps and drawwork.

The results were:

- HYDRAULIC DRAWWORK, weighing 32 tonnes compared to 85 tonnes, and still featuring:

- A failsafe braking system on the hoisting machinery.
- A dynamic braking and hoisting capacity to correspond to or even an improvement compared to existing drawworks.
- Single lever control for hoisting and lowering.
- Automatic WOB-control, much improved over conventional automatic drillers.
- Stepless control of transmission.
- Reduced mass of inertia.

- HYDRAULIC MUD PUMPS, weighing 3 x 8 tonnes compared to 3 x 42 tonnes, featuring the following:

- Ability to pump mud over the full range of flow and pressure without changing pistons and liners.
- Reduced pulsation of mudflow at high pressures.
- Reduced maintenance frequency on mud pumps.
- No wear on the liners because of a unique packing assembly.

- THE HYDRAULIC TOP DRIVE WEIGHING 15 TONNES COMPARED TO 19 TONNES featuring:

- A shortened total length.

- A center of gravity moved to center of the machine.

- Reduced outline dimensions in order to fit into smaller masts or derricks.

- Complying with hazardous area specification.

- An improved safety aspect by replacing el. power loop with hydraulic hoses.

- Increased redundancy with 4 pumps and 4 motors.

- THE HYDRAULIC ROTARY TABLE WITH REDUCED WEIGHT FROM 20 TO 14 TONNES

- Less space consuming as the DC motor and gearbox is removed.

The complete package could look like this where we also have considered the savings in primary and secondary steel.

Products	MH-Hydraulic equipment	Conventional equipment
Drawwork	32	85
3 x Mud Pumps	24	126
Rotary Table	14	20
Top Drive	14	18
Extra Power Units	40	0
Extra Support Steel	0	360
	124 tonnes	609 tonnes

Weight saving : 485 tonnes

The equipment savings should be clear to everyone. The structural steel savings are, however, more complicated to demonstrate.

Our calculations are based on two methods:

One - the rule of thumb saying that for each ton you save on equipment, you will save appr. 3 tonnes of structural steel.

Two - Our equipment is much smaller than conventional equipment and weight volume is as an average in drilling modules appr. 129 kg/m^3.

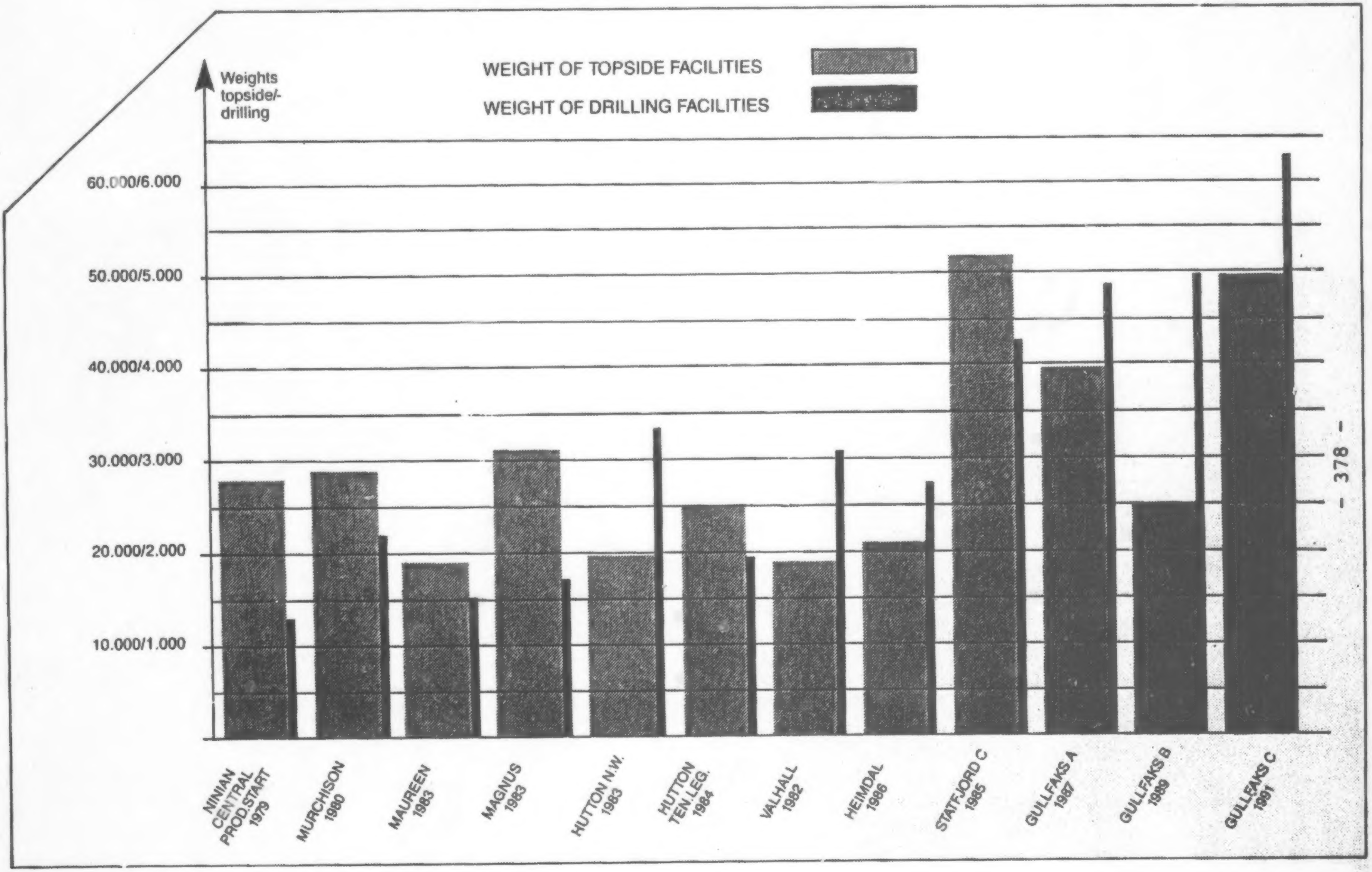
The rule of thumb's ratio of 1:3 is based on studying various oil fields in the North Sea. The weight distribution is as shown on this overhead.

The weight/volume figure is taken from the same oil field development study. It is clear how all the weights and volumes are plotted along a linear axis.

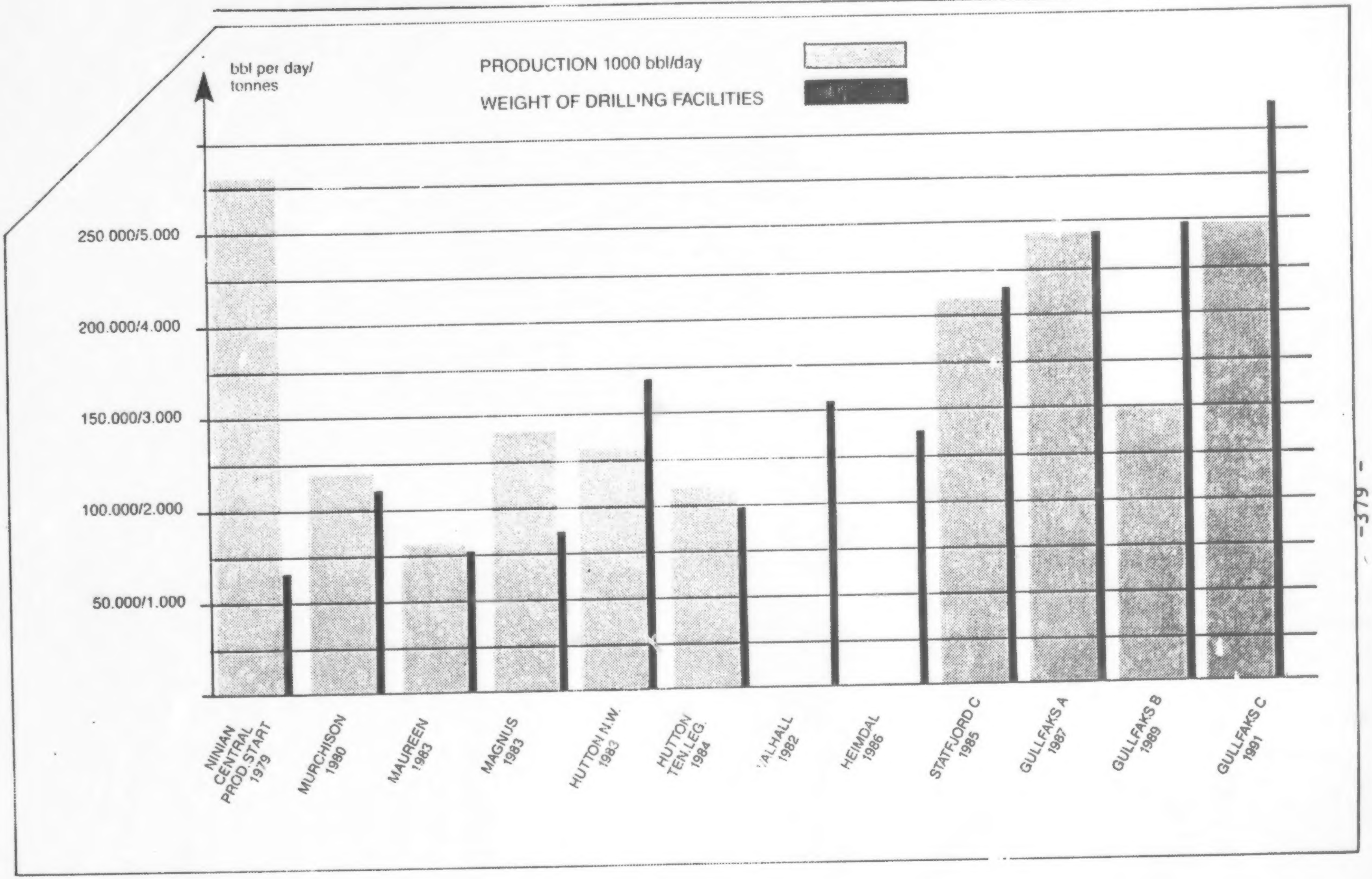
Now to the perhaps most interesting part, the cost distribution. As we will see from the overhead, the cost of structural steel and secondary steel is enormous.

That's why we can say that the money you will save on using 360 tonnes less steel, will more than buy you a complete Maritime Hydraulics drilling package.

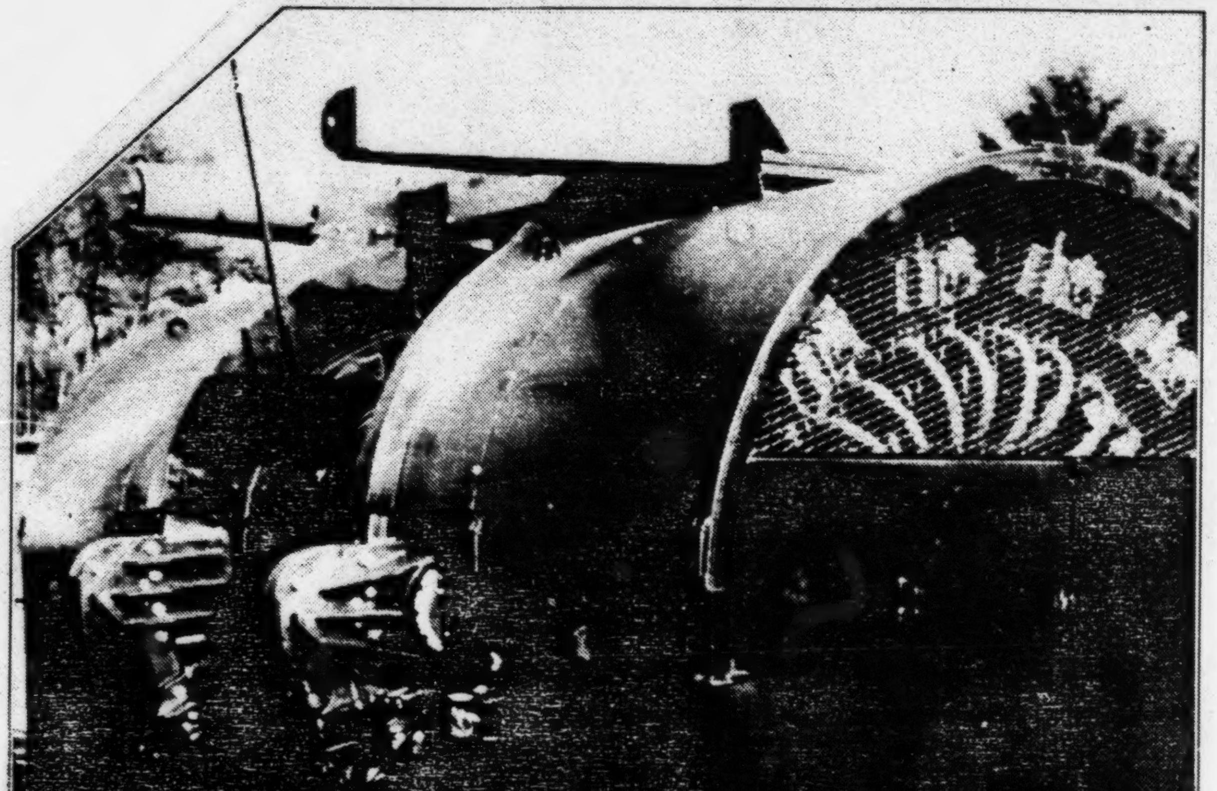
WEIGHT


WEIGHT OF TOPSIDE FACILITIES
WEIGHT OF DRILLING FACILITIES
Weights topside/-drilling
60.000/6.000
50.000/5.000
40.000/4.000
30.000/3.000
20.000/2.000
10.000/1.000
NINIAN CENTRAL PROD.START 1979
MURCHISON 1980
MAUREEN 1983
MAGNUS 1983
HUTTON N.W. 1983
HUTTON TEN.LEG. 1984
VALHALL 1982
HEIMDAL 1986
STATFJORD C 1985
GULLFAKS A 1987
GULLFAKS B 1989
GULLFAKS C 1991

WEIGHT

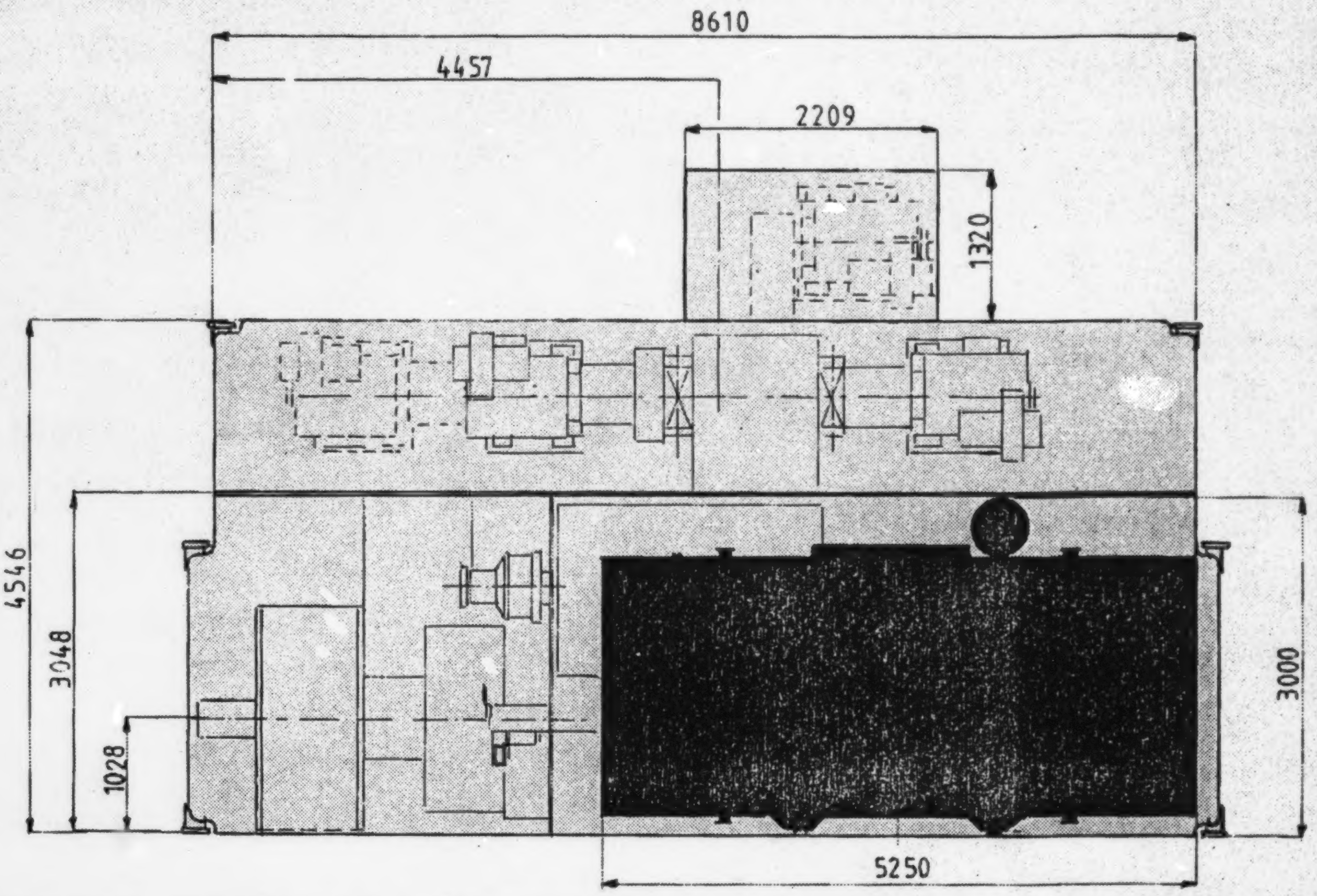

bbl per day/
tonnes
PRODUCTION 1000 bbl/day
WEIGHT OF DRILLING FACILITIES
250.000/5.000
200.000/4.000
150.000/3.000
100.000/2.000
50.000/1.000
NINIAN CENTRAL PROD.START 1979
MURCHISON 1980
MAUREEN 1983
MAGNUS 1983
HUTTON N.W. 1983
HUTTON TEN.LEG. 1984
VALHALL 1982
HEIMDAL 1986
STATFJORD C 1985
GULLFAKS A 1987
GULLFAKS B 1989
GULLFAKS C 1991

HYDRAULIC DRAWWORKS

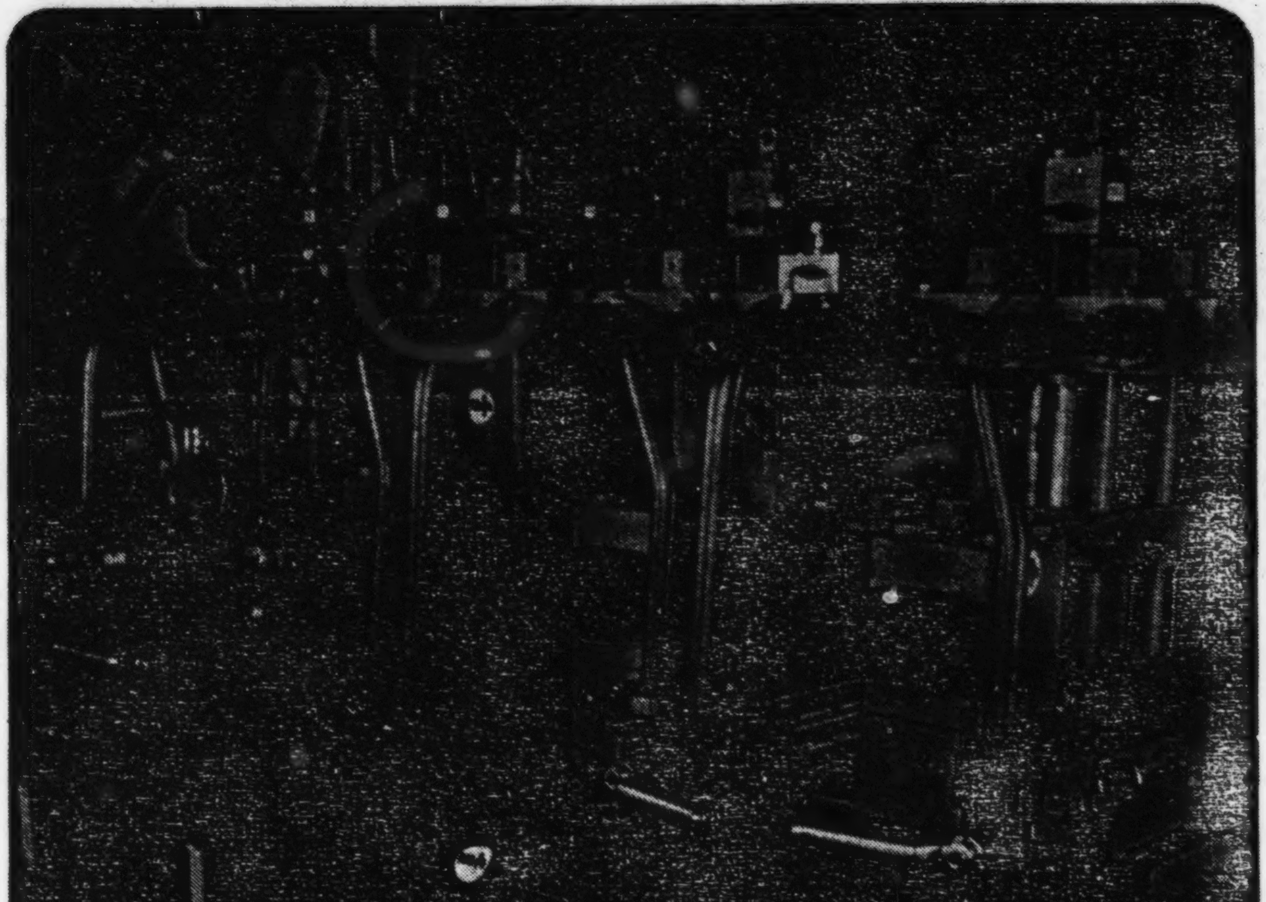


FOOTPRINT Conventional/MH-drawwork

Size comparizon plan view:
(Conventional VS. MH-500-20.)

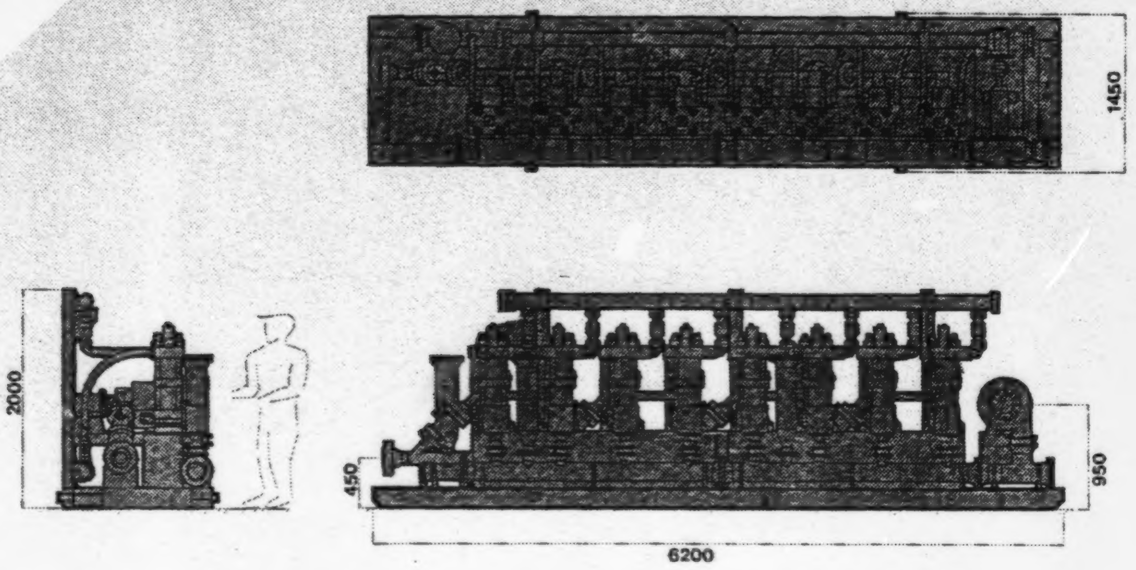

8610
4457
2209
1320
4546
3048
1028
3000
5250

MUD PUMP



HYDRAULIC MUD PUMP

MUDMASTER



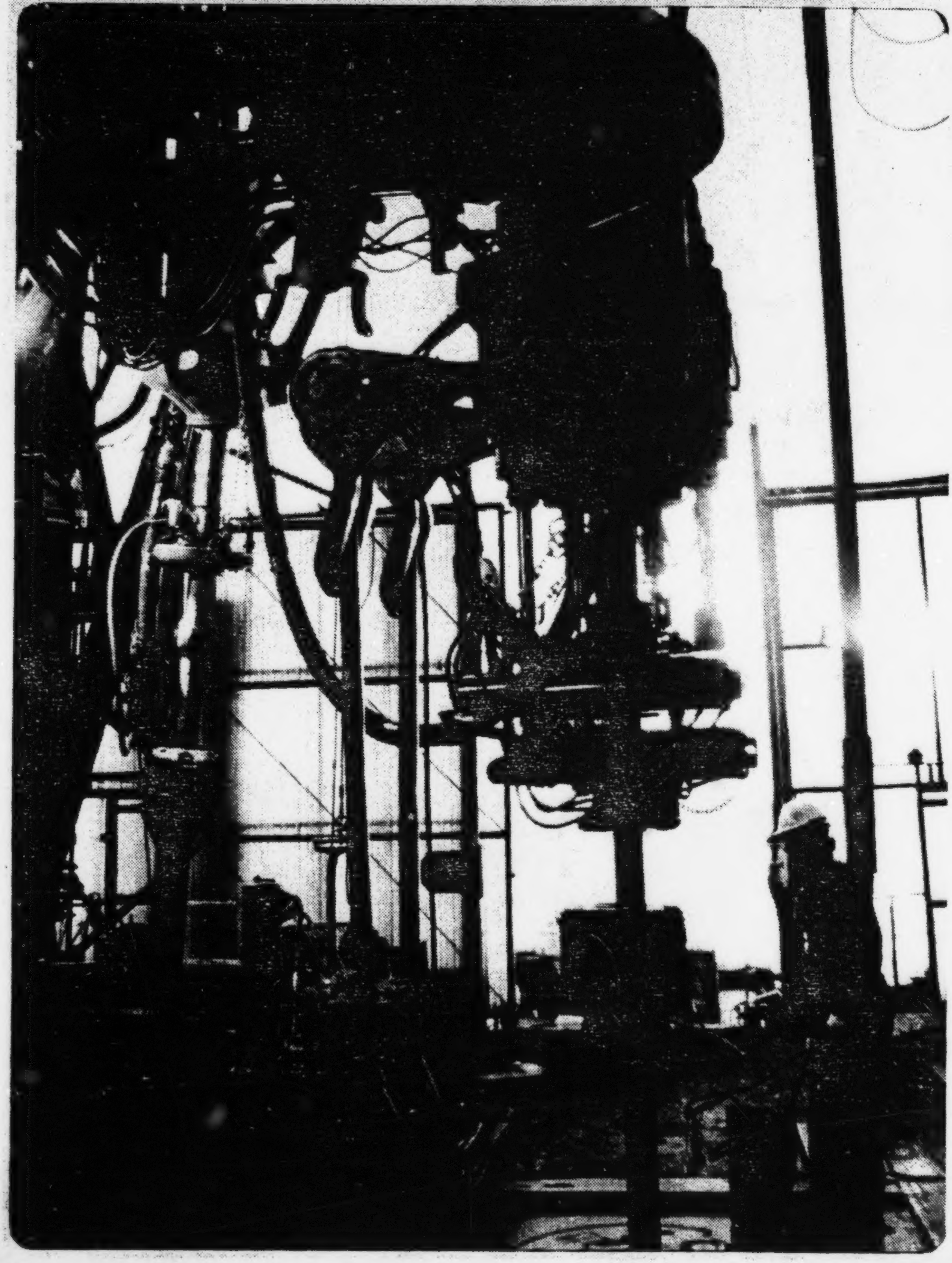
MODULAR SYSTEM

The basic two-cylinder configuration is designed to act as a modular unit in the pumping systems, which can be built up from one or more modules with identical layout to give the required capacity.
This approach offers further opportunities for savings in cost, weight and space, since only one extra two-cylinder set is needed in a multi-unit configuration for standby purposes.
As a result, present requirement of 100% redundancy with today's duplex or triplex mud pumps could be dramatically reduced.

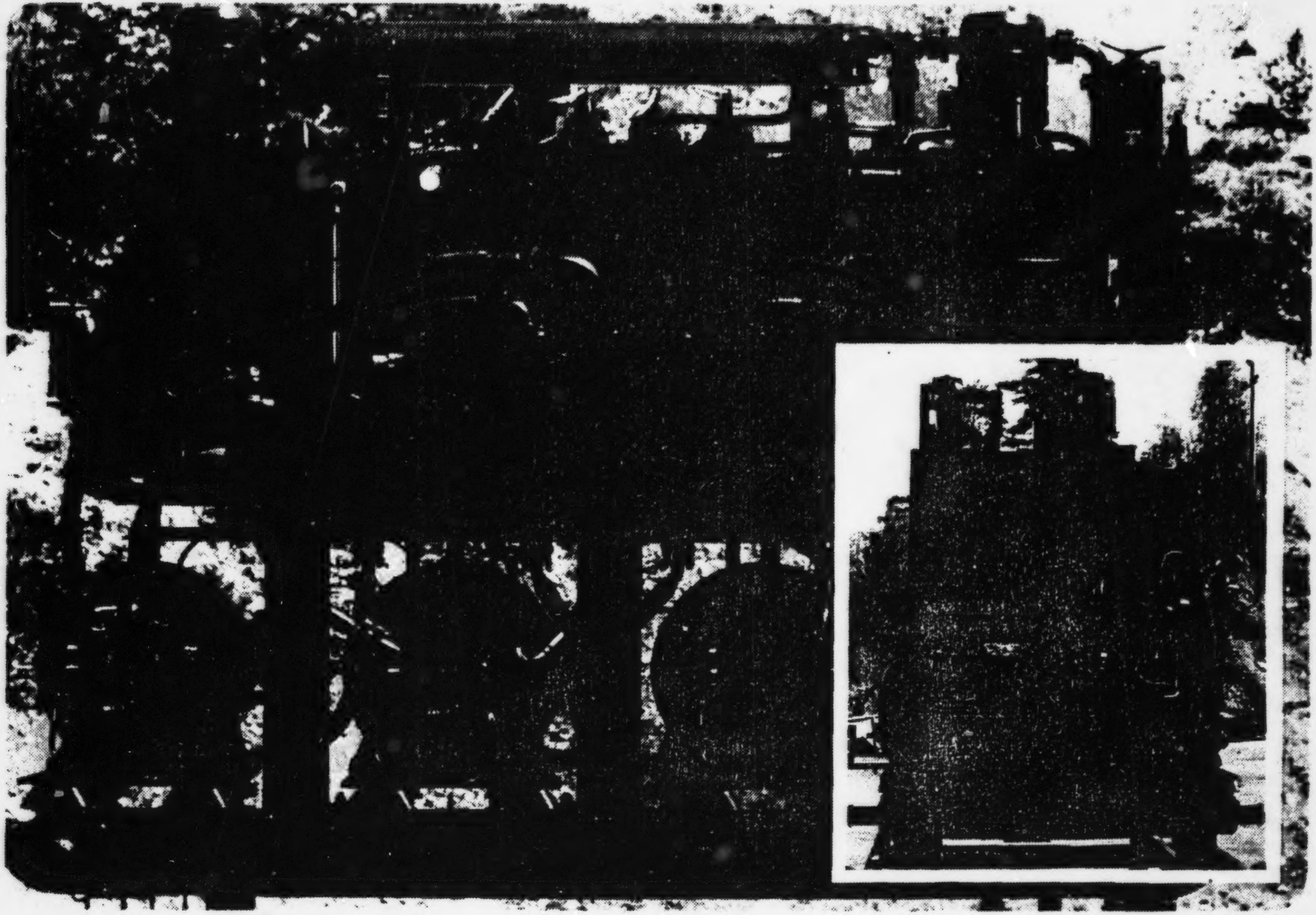
Technical specifications

Configuration:	4 dual pump cylinders in line
Mud flow mac. cont.:	2000 l/min (528 GPM)
Mud pressure max. cont.:	350 bar (5000 PSI)
Hydraulic flow input:	2000 l/min (528 GPM)
Hydraulic pressure input cont.:	350 bar (5000 PSI)
Flushing flow:	0,25% of mud flow, water for waterbased mud, oil for oilbased mud
Auxillary hydr. supply:	210 bar (3000 PSI) – 140 l/min (21 GPM)
Stroke volum:	4,19 l. (1,107 Gal.)
Max. speed:	60 SPM
Valves:	Suction/Discharge 2 in dia.
Weight:	7140 kg (15750 lbs) inkl. charging pump

Hydraulic **DDM 650**



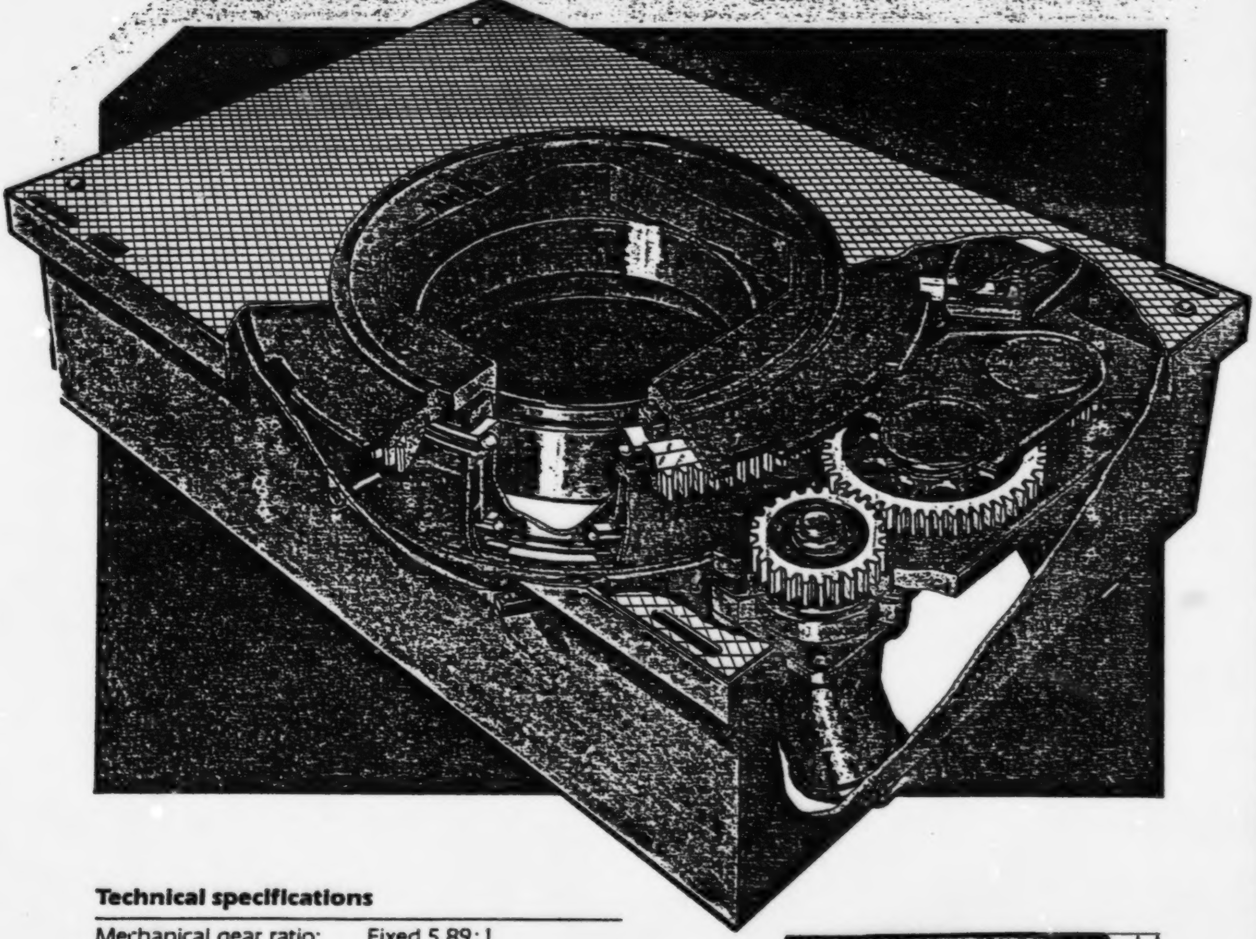
DDM Hydraulic Power Unit



HYDRAULIC POWERED ROTARY TABLE

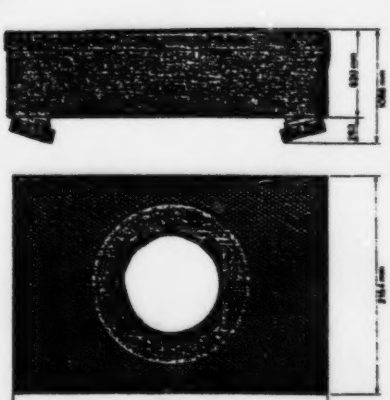
Performance characteristics are identical to the datas for DDM-HY. When a common power unit is used.

Other motor configuration available on request, example 4 x 500 ccm/rev. displacement, developes 51600 Nm (38100 ft.lbs.) torque.

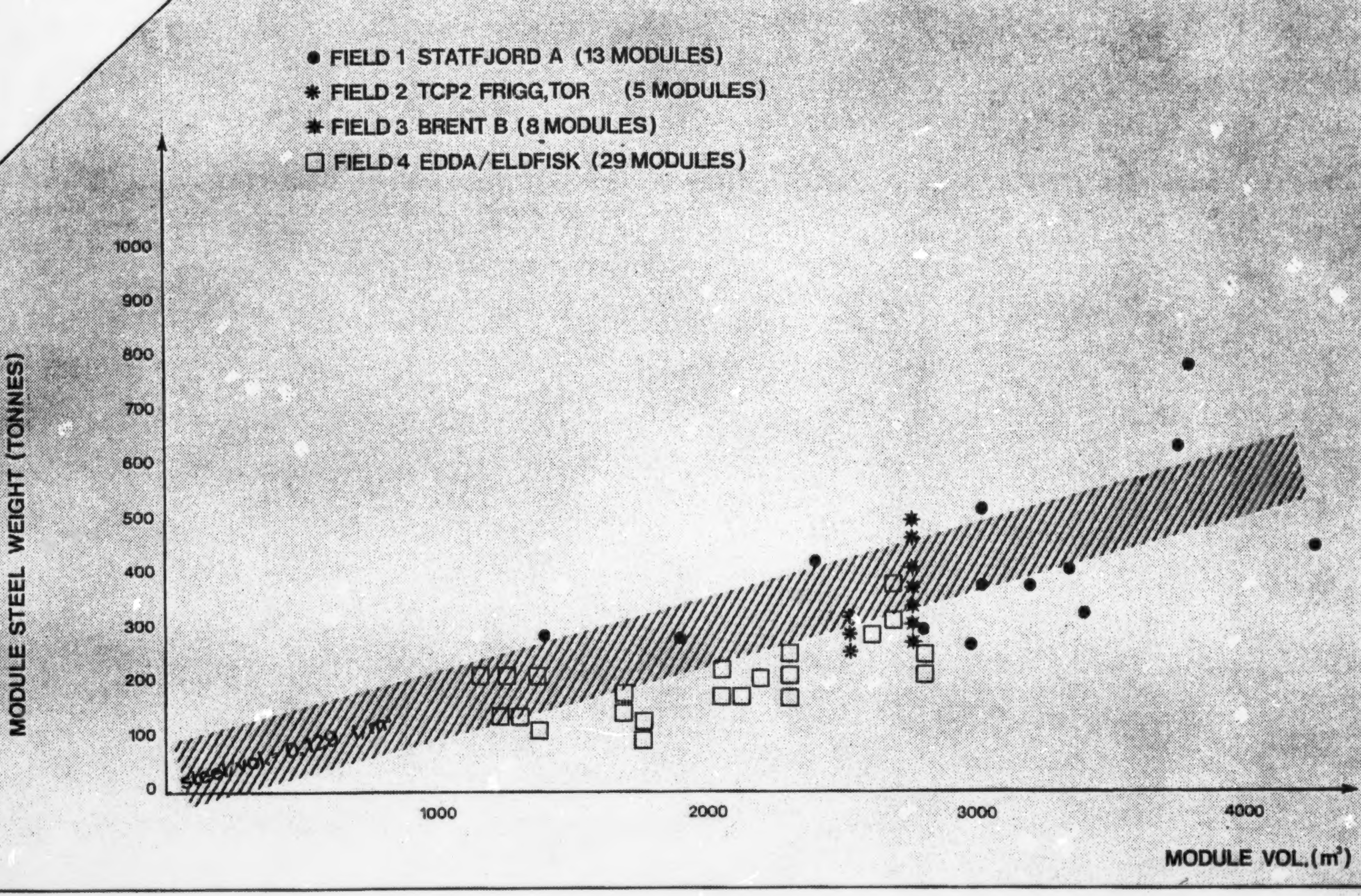


Technical specifications

Mechanical gear ratio:	Fixed 5,89: 1
Hydrastatic trans. ratio:	1,96: 1, five steps
Max. torque cont.:	42000 Nm (30300 ft.lbs.)
Max. torque int.:	49000 Nm (36100 ft.lbs.)
Speed at max. torque:	125 RPM
Max. speed:	245 RPM
Torque at max. speed:	21500 Nm (16000 ft.lbs.)
Total motor displacement:	4 x 468 ccm/rev. = 1876 ccm/rev. max. (957 ccm/rev. min)
Weight:	14000 kg

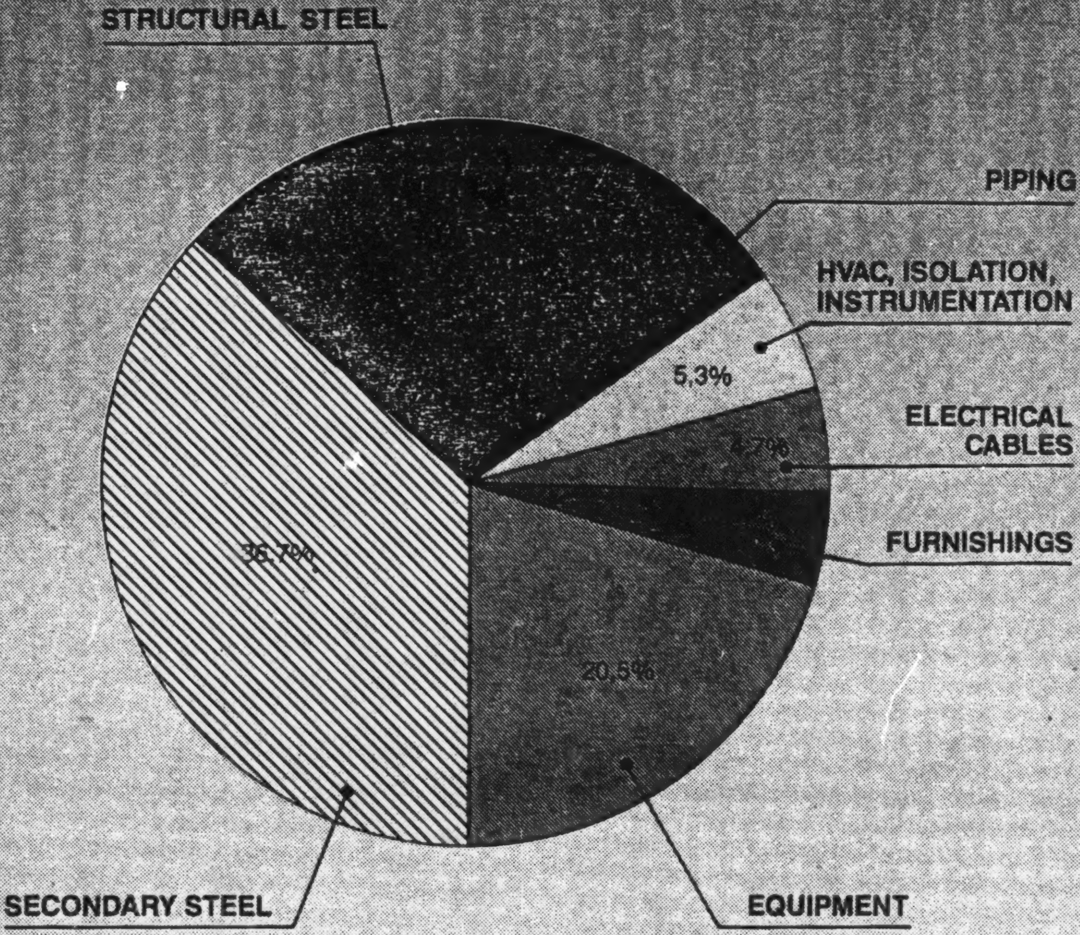


MODULE STEEL WEIGHT/VOLUME

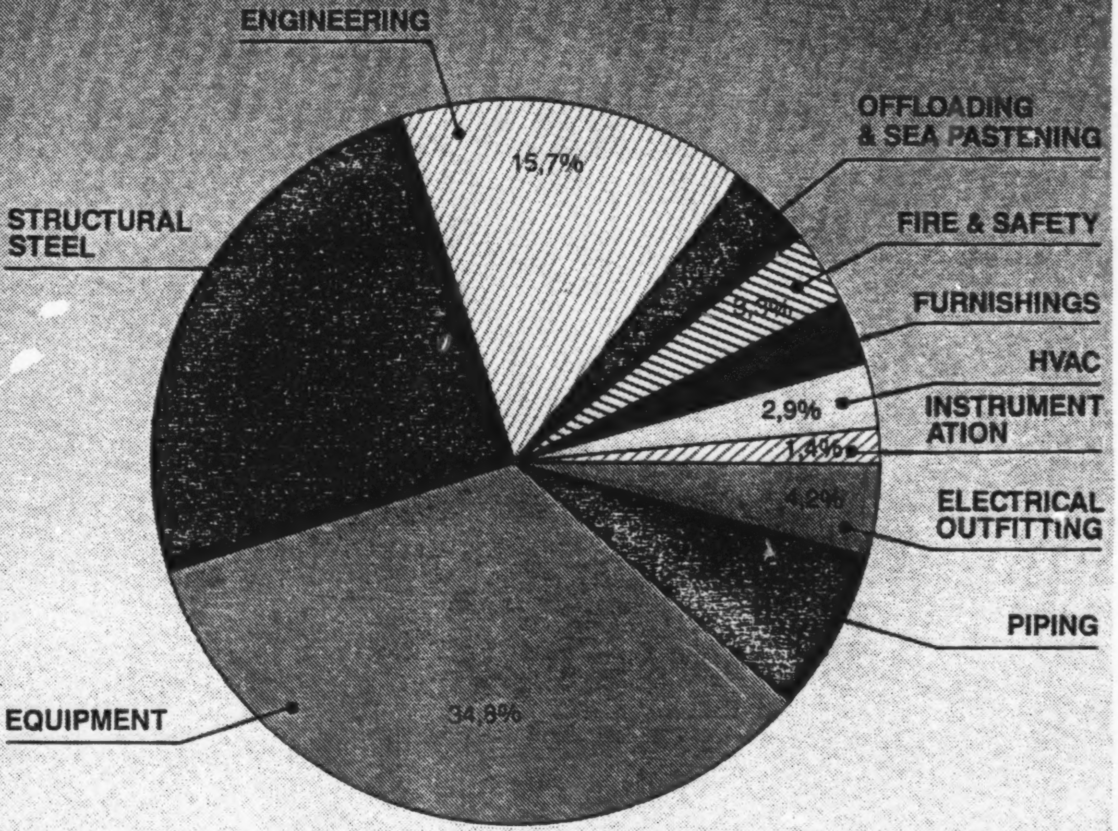


DRILLINGMODULES DRYWEIGHTS

WEIGHT DISTRIBUTION



COST DISTRIBUTION DRILLING MODULE



CLOSING LUNCHEON ADDRESS

by

THE HONOURABLE JAKE EPP

MINISTER OF ENERGY, MINES AND RESOURCES

CANADA

Since I was named Minister of Energy, Mines and Resources in January, Newfoundland has had a special place in my work. Hibernia is important for Newfoundland and it is also very important for me. It is one of the biggest undertakings ever entered into between the federal government, a province and the private sector. Given the size and complexity of the project, it is natural that it should be right at the top in terms of my priorities as Minister of Energy, Mines and Resources.

The Statement of Principles on Hibernia was signed in July 1988. A lot has happened since then, and I know this has given rise to questions and doubts in some minds regarding the status of Hibernia. Since July of last year, we have seen a federal election -- with a result which at least some of us found broadly satisfactory, even if somewhat disappointing in this province. Shortly after that, Brian Peckford announced his intention to resign as Premier of Newfoundland. There followed a period when energies here were focussed first on a leadership campaign and then on an election campaign. The election produced a new provincial government, which quite naturally requires some time to become immersed in major projects such as Hibernia. I want to emphasize that whatever our differences in political philosophy, my personal commitment is to work co-operatively with the Government of Newfoundland.

While there has been all this uncertainty at the political level, the project sponsors have also been doing some fundamental thinking. Not, I hasten to say, about the deal. But all of us are determined to bring the costs of this project down. While industry and Governments were prepared to proceed with Hibernia on the basis of a $5.2 billion estimate, we would all feel more comfort at a lower cost. In fact, we had based most of our early negotiations on a project cost of $4.2 billion and our deal capped key elements of the project assistance -- the incentive grant and guaranteed loan -- at that level.

It is also most important for further offshore development that this project be cost-effective and yield the maximum benefits possible to Newfoundland.

So we have revisited a number of elements of the project's design. The most significant is the possible move to five or six super modules that would sit on the concrete platform. These would replace the previously planned 20 smaller modules and main support frame. Consideration is also being given to smaller and fewer tankers, with a view to landing the oil in Newfoundland and then exporting it by supertanker. And the consortium is looking at an alternative, cheaper system for loading the oil from the platform.

No decision has been taken on any of these possible changes, but it is fair to say that at least some may be adopted. We are hopeful the re-designed project will be cheaper by several hundred million dollars. We should know that late this summer.

Uncertainty and change along with the possible revisions in project design could have provided an excuse for putting the project on hold. In fact, just the opposite has happened. Both Governments and the sponsors have been active since the fall in working out the detailed terms of this enormous undertaking. There have been committees on the net profit interest and royalties, financing, taxes and legal issues. These groups have met scores of times over the last several months drafting term sheets for the legally binding agreement. They have made excellent progress, so that only a small number of issues are now outstanding.

We did not meet our March 31, 1989, target for completing the agreement, but that was because of the volume and complexity of the work that had to be done.

But let there be no doubt. The Government of Canada is committed to completing this agreement. We believed in this project in July 1988, and we believe in it today. In fact, with the prospect of substantial cost improvements, we are even more confident of our commitment.

Let me say why we believe in Hibernia.

I am aware that some Canadians have been critical of the federal government's policy on mega-projects. I, like any taxpayer, would have preferred to see the Hibernia project proceed without Government support. But because of the significant benefits which will accrue to the people of Newfoundland and the rest of Canada, it is the federal government's responsibility to encourage development. With the project redesign and the associated potential reduction in costs, the economics of Hibernia will be better. We estimate that at today's oil prices, the underlying project would recover its costs with interest. And there is very significant upside if real oil prices are above $25 US in the late 1990s.

As you know, Hibernia will be the first major oil and gas project on the east coast of Canada. This means it is a strategic project in that it will open up the east coast to petroleum development. The building of the infrastructure, the expertise gained from the development of Hibernia and the confidence gained regarding project management and cost control in Newfoundland should lead to the development of other oil and gas projects such as Terra Nova and Whiterose.

Testing of Terra Nova has confirmed the existence of a good-quality, productive reservoir. Petro-Canada's most recent annual report continues to emphasize support for development of the Terra Nova discovery.

As you know, Husky has obtained promising results from the Whiterose discovery, and this represents another strong development opportunity. Hibernia, Terra Nova, and Whiterose are a clear sign that we are at the beginning of an era of major oil and gas developments in Newfoundland's offshore.

I can speak with complete confidence regarding the federal government's commitment to Hibernia. The complex piece of choreography that is Hibernia will require two governments and four companies. I cannot speak for my partners, but the companies are negotiating seriously.

I have read the recent Newfoundland Speech from the Throne and particularly references to the Hibernia development. It states, "The Statement of Principles signed last July would, if followed through completely, result in an agreement for the development of Hibernia", and then it goes on to state, "The Government will do everything within its power to ensure that the Hibernia oil field is developed without delay." I take these to be very positive statements. I am holding my first "get acquainted" session with Dr. Gibbons later today and expect we will have further substantive meetings soon after the new Cabinet has had an opportunity to review the project and the undertakings in the Statement of Principles in more detail.

Hibernia and subsequent projects promise a new, more vibrant economic future for the people of Newfoundland and Labrador.

The Atlantic Accord signed here in St. John's by the Prime Minister in February 1985, clearly states that the province of Newfoundland and Labrador is to be the principal beneficiary of offshore development. That commitment was reaffirmed in the Statement of Principles for Hibernia which was signed last July. Without exaggeration, it can be said that the billions of dollars to be invested in Hibernia over its six-year construction period will create significant economic opportunities and benefits for the residents of this province and the rest of Canada.

There are opportunities for Newfoundland and Labrador companies in all aspects of the project such as the design and construction of the massive concrete gravity base or GBS, the mechanical outfitting of the GBS, in onshore and offshore hook-up, and in the hundreds of services the project will require from catering to the provision of fuel for marine operations.

I know there is some concern in the province regarding the impact of the project's redesign on Newfoundland benefits. A smaller project, which is a more economic project, will by its nature have fewer benefits to share. But it is premature to draw any conclusions on what the net impact of project redesign might be. What I can tell you is that both Governments and the Canada-Newfoundland Offshore Petroleum Board will monitor this question very carefully and will ensure that there is a fair distribution of benefits for Newfoundlanders and other Canadians.

Jobs are only part of the benefits story. The development and operation of Hibernia will bring very significant project royalties, corporate income taxes and retail sales tax to governments.

Major offshore developments such as Hibernia are new to Canada, and we recognize that there is a need for foreign expertise to complete these projects safely, on schedule and within budget.

The presence at this conference of so many experienced international organizations shows there is a large pool of foreign expertise we can tap.

We also recognize that we must develop our own expertise in offshore oil and gas developments within Canada for future projects. We, therefore, encourage all forms of technology transfer which will help develop Canadian expertise. As you know, technology transfer is emphasized in the Statement of Principles for Hibernia.

Bidding for the first two major Hibernia contracts has already closed. I was pleased to note that all of the bidders for these two contracts were joint ventures between Canadian and Newfoundland companies and foreign firms. Joint ventures have been used in other industries and other countries as a successful means of transferring technology to local firms. These two contracts which are to design and build the GBS and to design the topsides and help manage the project have started Hibernia off in the right direction. We have high expectations for similar results throughout the project.

Bilateral groups have a similar role to play. The Canada-Norway Offshore Working Group, for example, has just completed a cross-Canada tour discussing offshore opportunities, not just in Canada, but in the Norwegian offshore.

The regulatory house for the Newfoundland offshore is in order. Jim Strain is now in place as the new Chairman of the Canada-Newfoundland Offshore Petroleum Board and he will, I'm sure, continue the good work undertaken by Ted Baugh. The Board has issued a Call for Bids for Exploration Licenses, which closes in September.

Two issues are of fundamental concern to the federal government and to the Board, in the development of Hibernia and other offshore oil fields: the environment and health and safety.

Our stance on these issues is one in which we ensure that risks are reduced to the lowest possible level.

In the case of health and safety, the absolute necessity for strict regulations was emphasized during the investigation of the Ocean Ranger disaster. That tragedy is now very much a part of any consideration of health and safety in the offshore for Newfoundlanders.

It is a concern shared by all Canadians, who grieved with you over the tragic loss of lives.

The health and safety requirements for offshore work in Canadian waters are among the most advanced in the world. The Canada-Newfoundland Offshore Petroleum Board monitors and enforces these standards for the Newfoundland offshore.

In recent years, the environment has become a major concern for Canadians. All Canadians who live and toil by the sea were affected by the Valdez environmental disaster and its toll on the fragile ecosystem. No Canadian, no North American, no human being, should be willing to be reckless with the environment.

The environmental aspects of Hibernia have been thoroughly studied in the Hibernia Environmental Impact Assessment process which included public hearings in a number of centres in Newfoundland.

The Canada-Newfoundland Atlantic Accord Implementation Act sets out the environmental requirements that must be fulfilled for offshore development. Memoranda of understanding between federal and provincial agencies will ensure timely coordination to resolve environmental issues and concerns.

The Hibernia development, and the Newfoundland offshore developments that will follow, will open a future full of promise.

With the development of Hibernia, we are committed to the completion of the first chapter of the new energy story that is to be written in this province. But it is a first chapter in what I hope will be a long, fascinating and exciting adventure.

Thank you.

LIST OF CONFERENCE ATTENDEES

(*) Indicates Speaker
(**) Indicates Moderator

WILLIAM ADISSON
SAINT JOHN SHIPBUILDING
P.O. Box 5111
Saint John
New Brunswick
E2L 4L4
(506) 632-3232

JOHN ANDREWS
Reservoir Engineer
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF A1C 6H6
(709) 778-1400

WAYNE ASH
INSPECTION SERVICES
FOLLETT GOSSE &
ASSOCIATES LIMITED
P.O. Box 9485
St. John's, NF
A1A 2Y4
(709) 738-3491

ROY ASPDEN
Project Manager
MIL DEGROOT INC.
Klubbgaten 11
P.O. Box 729
4001 Stavanger
NORWAY

MARCEL AYEKO
MARINE INSTITUTE
P.O. Box 4920
St. John's, NF
A1C 5R3
(709) 778-0409

MICHAEL AYRE
Vice-President
MIL DAVIE, INC.
P.O. Box 130
Levis, Quebec
G6V 6N7
(418) 837-5841

JOHN BARTOVSKY
Marketing Manager
EH INDUSTRIES (CANADA)
700-275 Slater Street
Ottawa, Ontario
K1P 5H9
(613) 563-2180

ALAN W. BEARDALL
Project Executive,
Industrial Benefits
DEPARTMENT OF COMMERCE
& TECHNOLOGY
P.O Box 6000 Fredericton
New Brunswick E3B 5H1
(506) 453-2102

BERNIE BEAUPERTUIS
Materials Co-ordinator
PETRO-CANADA INC.
P.O. Box 5190
St. John's, NF
A1C 6H2
(709) 722-2621

J. R. BENOIT
Facilities Specialist
MOBIL OIL CANADA
PROPERTIES
Box 62, Atlantic Place
215 Water Street
St. John's, NF A1C 6C9
(709) 778-7525

PER BERGREM
Manager, Marketing/
Projects
DET NORSKE VERITAS
#1110, 10201 Southport
Road South West
Calgary, Alberta T2W 4X9
(403) 253-3422

TOMASZ BERZOWSKI
Vice-President
NORTEK ENGINEERING INC.
220 LeMarchant Road
St. John's, NF
A1C 2H8
(709) 739-6749

JOHN A. BLOMFIELD
Manager Terra Nova
Task Force
PETRO-CANADA RESOURCES
2854 PCCW, 150-6 Ave
S.W. Calgary, Alberta
T2P 3E3
(403) 296-5518

WALTER BOBBY
Senior Structures Eng.
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF A1C 6H6
(709) 778-1415

PATRICK BOISSERTE
Economist-Engineer
INSTITUT FRANCAIS
DU PETROLE
1-4 Ave. de Bois-Preau
Rueil Malmaison Cedex
92506 FRANCE
(33) 1 47-526767

HAROLD BOWN
Instructor
Construction &
Resources Programs
CABOT INSTITUTE
P.O. Box 1693
St. John's, NF A1C 5P7
(709) 778-2291

RODNEY BURSEY
Engineer
FOLLETT, GOSSE &
ASSOCIATES LIMITED
P.O. Box 9485
St. John's, NF
A1A 2Y4
(709) 753-2100

WAYNE BUSSEY
General Manager,
Corp. Development
NEWFOUNDLAND TELEPHONE
P.O. Box 2110
St. John's, NF
A1C 5H6
(709) 739-2610

ROBERT BYRNE
Store Manager
NATIONAL-OILWELL
CANADA LIMITED
P.O. Box 338
Mount Pearl, NF
A1N 2C3
(709) 364-2367

ROGER CAISSIE
Vice-President
Operations
ATLAS TESTING LABS AND
SERVICES (NFLD) LIMITED
P.O. Box 2050
Port aux Basques, NF
A0M 1C0
(709) 695-7031

RICHARD CALLAHAN
Business Manager
COTE'S MECHANICAL
LIMITED P.O. Box 237
Stephenville, NF
A2N 2Z4
(709) 643-5666

M. D. CALLANDER
Regional Manager
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

JOHN CAPPS
Vice-President,
Engineering
NORDCO LIMITED
P.O. Box 8833
St. John's, NF
A1B 3T2
(709) 364-1200

JOHN E. CARLSON
President
ISLAND ENGINEERING CO.
P.O. Box 975
Corner Brook, NF
A2H 6J3
(709) 634-6973

JEAN CARTIER
TOPSIDE CONTRACTORS
OF NEWFOUNDLAND
LIMITED
P.O. Box 5680
St. John's, NF
A1C 5W8
(709) 579-2010

DR. LINDA CLARKE
Director, Marine
Industries
DEPT. OF DEVELOPMENT
P.O. Box 4750
St. John's, NF
A1C 5T7
(709) 576-5592

NATH COOPER
Vice-President
HARVEY SERVICES
LIMITED
P.O. Box 5128
St. John's, NF
A1C 5V6
(709) 726-8000

(*)JOHN COPELAND
Quality Assurance
Manager
MOBIL OIL CANADA
PROPERTIES
P.O. Box 62
St. John's, NF
A1C 6C9
(709) 778-7000

FINTAN COSTELLO
Assistant Director
Post Secondary Ed.
DEPT. OF EDUCATION
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-5760

PAUL COTE
President
COTE'S MECHANICAL
LIMITED
P.O. Box 237
Stephenville, NF
A2N 2Z4
(709) 643-5666

PETER COX
Vice-President,
Marketing
West Canada
SNC/AKER
OFFSHORE INC.
290 Midpark Way SE
Calgary, Alberta
T2X 1P1
(403) 256-9445

ANDREW CRICHTON
FACULTY OF BUSINESS
MEMORIAL UNIVERSITY
OF NEWFOUNDLAND
St. John's, NF
A1B 3X5
(709) 737-8823

PETER CROCKER
Engineering Manager
BFL CONSULTANTS
LIMITED
P.O. Box 12070
St. John's, NF
A1B 3T5
(709) 753-6252

GRAHAM CURREN
Chartering Manager
SECUNDA MARINE
SERVICES LIMITED
P.O. Box 605
Dartmouth
Nova Scotia
B2Y 3Y9
(902) 465-3400

HAL DAVIES
SAINT JOHN
SHIPBUILDING
P.O. Box 5111
Saint John
New Brunswick
E2L 4L4
(506) 632-3232

PAUL C. DEHAN
Vice-President
MOBIL SHIPPING &
TRANSPORT CO.
150E 42nd Street
New York
U.S.A. 10017
(212) 883-4656

BEN DEMPSEY
Manager, Offshore
Projects
HALIFAX-DARTMOUTH
INDUSTRIES LIMITED
P.O. Box 1477
Halifax, Nova Scotia
B3K 5H7

M. DEVINE
Project Manager
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

TERRENCE DOYLE
President
NABORS DRILLING LIMITED
1100, 505-3rd Street SW
Calgary, Alberta
T2P 3E6
(403) 263-6610

ROBERT DRYDEN
TOPSIDE CONTRACTORS OF
NEWFOUNDLAND LIMITED
P.O. Box 5680
St. John's, NF
A1C 5W8
(709) 726-2160

ROBERT DYCK
Drilling Superintendent
ESSO RESOURCES CANADA
237-4th Avenue S.W.
Calgary, Alberta
T2P 0H6
(403) 237-2076

FRASER EDISON
NEWFOUNDLAND OFFSHORE
DEVELOPMENT CORPORATION
139 Water Street
P.O. Box 2446
St. John's, NF
A1C 6E7
(709) 753-4651

ALLISON J. ENGLAND
Development Officer
ENTERPRISE CAPE BRETON
CORPORATION (ECBC)
P.O. Box 610
Port Hawkesbury
Nova Scotia B0E 2V0
(902) 625-3111

HARVEY ERICKSON
Manager
NATIONAL-OILWELL
CANADA LIMITED
9450-45th Avenue
Edmonton, Alberta
T6E 5V3
(403) 437-4400

JOHN FITZGERALD
Vice-Chairman
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF A1C 6H6
(709) 778-1400

ROGER FLOOD
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

(**)DAVID FONG
President
RDS ENGINEERING
LIMITED
253 Duckworth Street
St. John's, NF
A1C 1G8
(709) 739-5473

WESLEY FOOTE
Instructor
Petroleum Technology
CABOT INSTITUTE
P.O. Box 1693
St. John's, NF
A1C 5P7
(709) 778-2540

ROBERT FORBES
President
BFL CONSULTANTS
LIMITED
P.O. Box 12070
St. John's, NF
A1B 3T5
(709) 753-6252

(*)LARS FOYEN
President
DET NORSKE VERITAS
(CANADA) LTD.
1110-10201 Southport
Road S.W.
Calgary, Alberta T2W 4X9
(403) 253-3422

PETER FURLONG
INDUSTRY, SCIENCE
& TECHNOLOGY CANADA
P.O. Box 8950
St. John's, NF
A1B 3R9
(709) 772-4866

MICHEL GAGNON
Director
MIL TRACEY INC.
P.O. Box 550
Sorel, Quebec
J3P 5P5
(514) 743-3351

(*)GERRY GERMAIN
President
BOUYGUES OFFSHORE
CANADA LIMITED
Suite 1219
1505 Barrington Street
Halifax, Nova Scotia
B3J 3K5
(902) 422-5534

BRUCE GIBBON
Manager, Field Sales
HONEYWELL LIMITED
155 Gordon Baker Road
North York, Ontario
M2H 3N7
(416) 490-3035

ROBERT GILL
Project Engineer
ACRES INTERNATIONAL
LIMITED
P.O. Box 13337, Stn. A
St. John's, NF
A1B 4B7
(709) 754-1710

REUBEN GOLDMAN
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

(*)LESLIE GOMM
Chemical Engineer
BAILEY CONTROLS
860 Harrington Court
Burlington, Ontario
L7N 3N4
(416) 639-8840

S. JOHN GORMAN
District Manager
DET NORSKE VERITAS
183 Place Frontenac
Pointe Claire
Quebec
H9R 4Z7
(514) 695-0735

BRUCE GRESHAM
Commercial Rep.
N & S America
HEEREMA
17154 Butte Creek
Suite 200
Houston, Texas
77090
(713) 893-3090

JOHN B. HANRAHAN
Systems Marketing
BAILEY CONTROLS
860 Harrington Court
Burlington, Ontario
L7N 3N4
(416) 639-8840

KNUT E. HANSEN
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

RAYMOND D. HARVEY
Vice-President
LAVALIN LIMITED
2235 Sheppard Ave E
Willowdale, Ontario
M2J 5A6
(416) 756-1643

DAVID W. HAWKINS
Director, Petroleum
Resource Development
DEPT. OF MINES
& ENERGY
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-2323

KEITH HAWLEY
Manager, Benefits
Offshore Development
Division
DEPT. OF DEVELOPMENT
P.O. Box 4750
St. John's, NF A1B 4J6
(709) 576-5064

JOHN J. HENLEY
Manager, Marine
Engineering
NORDCO LIMITED
P.O. Box 8833
St. John's, NF
A1B 3T2
(709) 364-1200

DIEGO HENAO
Vice-Chairman
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF
A1C 6H6
(709) 778-1400

(*)DAVID HEWLETT
Engineer
NORTEK
ENGINEERING INC.
22 LeMarchant Road
St. John's, NF
A1C 2H8
(709) 739-6749

C. NEIL HENRY
Engineer, Design
& Construction
CHEVRON CANADA
RESOURCES
500-5th Avenue SW
Calgary, Alberta
T2P 0L7
(403) 234-5173

CLAYTON HIGDON
Account Manager
ATLANTIC CANADA
OPPORTUNITIES
AGENCY (ACOA)
P.O. Box 1060
STN "C"
St. John's, NF
A1C 5M5

HEINRICH HOFFMAN
Mechanical Engineer
KSB AG
4415 Sarellen Road
Richmond, Virginia
U.S.A. 23231
(804) 222-1915

BOYD HOWELL
Engineer
BOUYGUES OFFSHORE
CANADA LIMITED
280 Torbay Road
St. John's, NF
A1A 3W8
(709) 726-2218

JOHN HUDSON
Professional
Engineer
DEPT OF
DEVELOPMENT
P.O. Box 4750
St. John's, NF
A1C 5T7
(709) 576-5064

DOUGLAS HUNT
Petroleum
Eng. Consultant
DEPT OF MINES
& ENERGY
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-6813

(**)**BRIAN JONASSON**
Manager, Operations
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
5th Floor, TD Place
140 Water Street
St. John's, NF
A1C 6H6
(709) 778-1400

D. I. JONES
Dir., Commercial New
Business Development
SAINT JOHN
SHIPBUILDING
P.O. Box 970
Saint John
New Brunswick E2L 4E5
(506) 633-5539

GEORGE KALBA
Quality Control
Supervisor
PETRO-CANADA
RESOURCES
P.O. Box 2844, Calgary
Alberta T2P 3E3
(403) 296-7611

J. A. KELLY
Vice-President,
Property Development
MOBIL OIL CANADA
PROPERTIES
Box 62, Atlantic Place
St. John's, NF A1C 6C9
(709) 778-7217

(*)**FATHI KHALIL**
Senior Project Manager
SNC/AKER OFFSHORE INC.
290 Midpark Way SE
Calgary, Alberta T2X 1P1
(403) 256-9445

JAMES KINLEY
Chairman
OFFSHORE TRADE
ASSOCIATION OF
NOVA SCOTIA
Suite 813, 1800 Argyle
Street, Halifax
Nova Scotia B3J 3N8
(902) 425-4774

ARNT KNUDSEN
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

ROY LAMBE
President
METAL FAB LIMITED
P.O. Box 9567
St. John's, NF
A1A 2Y4
(709) 576-8881

THOMAS H. LANDER
Chief Inspector
COGLA HALIFAX
2000 Barrington Street
Suite 102
Halifax, Nova Scotia
B3J 3K1
(902) 426-8570

(*)**CRAIG LANG**
Technical Director
SEAWAYS ENGINEERING
(UK) LIMITED
York House 5a Lancaster
Road, Wimbledon Village
London, England SW1 5DA
(01) 944-1599

DAVID J. LEITH
General Manager
DIAMOND GLASS &
ALUMINUM PRODUCTS
C-7464 Gilley Avenue
Burnaby, British Columbia
V5J 4X6
(604) 433-2491

JEAN-PIERRE L'ESPERANC
President
ACIERS JPL INC. -
LOKOMO STEEL WORKS
8 Matton
Sorel, Quebec
I3P 2S3
(514) 743-1835

ARTHUR LEUNG
Program Consultant
DEPT OF EDUCATION
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-5760

GREGORY LEVER
Senior Engineering
Advisor
PETRO-CANADA RESOURCES
2850 PCCW
150-6th Ave SW
Calgary, Alberta
T2P 3E3
(403) 296-5518

DR. JOHN W. LEVERTON
Manager, Operational
Development
EH INDUSTRIES INC.
1735 Jeffer Dars Hwy.
Suite 805, Arlington
Virginia 22202
(703) 486-8000

(*)**ARNE LINDEKLEIV**
Marketing Manager
MARITIME
HYDRAULICS A/S
Dvergsres
N-4604 Kristiansand
Norway
47-02-246420

KATO LONE
Project Manager
FLAKT ROSS INC.
304 St. Patrick
LaSalle, Quebec
H8N 2H1
(514) 366-5160

STEVEN MA
Senior Advisor
Business Development
PETRO-CANADA RESOURCES
2834W 150-6th Ave. SW
Calgary, Alberta
T2P 3E3
(403) 296-5518

J. L. MACDONALD
Manager
BLACK & MCDONALD LTD.
617 Windmill Road
Dartmouth, Nova Scotia
B3B 1B6
(902) 465-3101

WILLIAM MANN
CANARCTIC SHIPPING
COMPANY LIMITED
350 Sparks Street
Suite 1005
Ottawa, Ontario
K1R 7S8
(613) 234-8414

(*)JOHN MANNING
OFFSHORE CERTIFICATION
BUREAU
61 Soutwark Street
London, England
SE1 1SA
01-620-0802

ERNST MARTHINUSSEN
Technical Manager
DET NORSKE VERITAS
#1110, 10201 Southport
Road South West
Calgary, Alberta
T2W 4X9
(403) 253-3422

MICHAEL MCCRADY
CABOT INSTITUTE
P.O. Box 1693
St. John's, NF
A1C 5P7
(709) 778-2400

DEREK MCDONALD
Marine Environmental
Engineer
ENVIRONMENT CANADA
15th Floor
Queen Square
45 Aldernay Drive
Dartmouth, Nova Scotia
B2Y 2N6
(902) 426-6892

HUGH MCLEOD
NORTH ATLANTIC
CONTRACTORS LIMITED
P.O. Box 5070
St. John's, NF
A1C 5V3
(709) 726-5000

JOHN C. MCSTAY
General Manager
MIL OFFSHORE INC.
61 Estates Road
Dartmouth, Nova Scotia
B2Y 4K3
(902) 465-2225

PAUL MOLLOY
Manager, Quality
Assurance
S.E.A. LIMITED
P.O. Box 13606
Stn. A
St. John's, NF
A1B 4G1
(709) 364-2075

DOUG MOODY
Director, Technology
Development
DEPT OF DEVELOPMENT
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-5061

BRIAN MUNROE
ATLAS TESTING LABS &
SERVICES (NFLD) LTD.
P.O. Box 2050
Port Aux Basques, NF
A0M 1C0
(709) 695-7031

PAUL MURPHY
Public Information
Officer
DEPT OF DEVELOPMENT
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-5586

GAVIN MURRAY
GIBSON
SHIPBROKERS LTD.
1 Westmount Square
Montreal, Quebec
H3Z 2P9
(514) 933-7371

FRED MURRIN
Director, Offshore
Development Division
DEPT OF DEVELOPMENT
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-5064

CAS NEGENMAN
Commercial Manager
HEEREMA
Vondellaan 47
2332 AA, Leiden
the Netherlands
071-351535

PETER NICHOLSON
HONEYWELL LIMITED
135 Jesley Avenue
Dartmouth
Nova Scotia
B3B 1T1
(902) 465-2400

FRANK NOLAN
Director
INDUSTRY, SCIENCE
& TECHNOLOGY
P.O. Box 8950
90 O'Leary Avenue
St. John's, NF
A1B 3R9
(709) 772-4878

GERRY O'CONNELL
ERDA Co-ordinator
ATLANTIC CANADA
OPPORTUNITIES AGENCY
1 Harbourside Drive
Charlottetown
Prince Edward Island
C1A 8R4
(902) 566-7487

STEPHEN O'DEA
Manager, Corporate
Development
NEWFOUNDLAND TELEPHONE
P.O. Box 2110
St. John's, NF A1C 5H6
(709) 739-2610

JOHN H. O'NEILL
Project Officer
Industrial Benefits
DEPT. OF COMMERCE
& TECHNOLOGY
P.O. Box 6000
Fredericton
New Brunswick E3B 5H1
(506) 453-2102

ANDREW A. ORAM
Vice President
BARCLAYS BANK PLC
75 Wall Street
New York, New York
USA 10265
(212) 412-5839

ANDY PARKER
Manager, Petroleum
Resources
NOVA SCOTIA DEPARTMENT
OF MINES AND ENERGY
P.O. Box 1087
Halifax, Nova Scotia
B3J 2X1
(902) 424-4575

REX T. PARSONS
President
NEWFOUNDLAND DESIGN
ASSOCIATES LIMITED
280 Torbay Road
St. John's, NF A1A 3W8

CLAUDE PATRY
TOPSIDE CONTRACTORS OF
NEWFOUNDLAND LIMITED
P.O. Box 5680
St. John's, NF
A1C 5W8
(709) 579-2010

JEAN PAYNE
P.C.M. GROUP INC.
P.O. Box 191
St. John's, NF
A1C 5J2
(709) 722-1200

(*)WILLIAM PENNEY
Lecturer
Marine Technology
UNIVERSITY OF
NEWCASTLE-UPON-TYNE
Newcastle Upon Tyne
England NE1 7RU
091-232-8511

WILLIAM PERRIN
NDE Supervisor
PROV. OF NEW BRUNSWICK
RESEARCH &
PRODUCTIVITY COUNCIL
Frederickton
New Brunswick
E3B 5H1

(*)HANS ROLFSMAN
Project Manager
GVA INTERNATIONAL LIMITED
25-28 Old Burlington St.
London, England
W1X 1LB
441-499-9944

JOHN REED
Area Manager
N & S America
HEEREMA
17154 Butte Creek
Suite 200
Houston, Texas 77090
(713) 893-3090

DAVID REID
TOPSIDE CONTRACTORS
OF NEWFOUNDLAND
P.O. Box 5680
St. John's, NF
A1C 5W8
(709) 726-2160

B. G. RENBORG
President
GVA CANADA LIMITED
P.O. Box 13959
St. John's, NF
A1B 4G7
(709) 364-9154

PAUL L. RITCEY
Vice-President
EASTERN CANADA
TOWING LIMITED
P.O. Box 337
Halifax, Nova Scotia
B3J 2N7
(902) 423-7381

JOHN ROBERTSON
Senior Sales
NATIONAL-OILWELL
CANADA LIMITED
9450-45th Avenue
Edmonton, Alberta
(403) 437-4400

ROBERT ROBINSON
Manager
DEPT. OF DEVELOPMENT
P.O. Box 4750
St. John's, NF
A1C 5T7
(709) 576-3246

(*)LAWRENCE ROGERS
President
QUALITY MANAGEMENT
INSTITUTE (CSA)
4 Robert Speck Parkway
Mississauga, Ontario
L4Z 1S1
(416) 272-3920

PETER ROGERS
Engineer
BFL CONSULTANTS
LIMITED
P.O. Box 12070
St. John's, NF
A1B 3T5
(709) 753-6252

(*)ILTON. J. ROSSETTO
Technical Assistant
Exploration &
Production Director
PETROBRAS
Petroleo Brasileiro SA
Avenue Chile, 65
GDWF Room 2336, Rio De
Janeiro, Brasil 20035
55-21-534-1103

MAXWELL RUELOKKE
Director
DEPT. OF DEVELOPMENT
P.O. Box 4750
St. John's, NF
A1C 5T7
(709) 576-2988

MORDAL RUNE
STATOIL
P.O. Box 300
N-4001 Stavanger
Norway
47-04-808080

(*)BARRY RYAN
Managing Director
SEAWAYS ENGINEERING
(UK) LIMITED
York House
5a Lancaster Road
Wimbledon Village
London, England SW1 5DA
(01) 944-1599

KENNETH RYAN
Senior Supervisor
CANADIAN COAST GUARD
Canada Building
344 Slater Street
Ottawa, Ontario
K1A 0N7
(613) 991-3163

(*)EINAR S. RYTTING
Vice President
EB CONSULTANTS A/S
P.O. Box 190
N-1371 Asker
Norway
47-02-795060

LAWRENCE SAVONA
Vice-President
BLACK &
MCDONALD LTD.
31 Pullman Court
Scarborough
Ontario
M1X 1E4
(416) 298-9977

SADIE SELLARS
Structural Engineer
NEWFOUNDLAND DESIGN
ASSOCIATES LIMITED
Bally Rou Place
280 Torbay Road
St. John's, NF
A1A 3W8
(709) 726-4490

LARRY SELLICK
Vice-President
MIL GROUP INC.
700-1600
Carling Avenue
Ottawa, Ontario
K1Z 8R7

M. T. SHARP
Vice-President
BLACK &
MCDONALD LTD.
557 Cambridge
Street S
Ottawa, Ontario
K1S 4J4
(613) 238-1226

LEE SHINKLE
Senior
Vice-President
REED STENHOUSE
P.O. Box 12000
St. John's, NF
A1B 3T6
(709) 739-1000

FRED T. SHORTTS
Regional Sales Man.
NOVENCO CANADA INC.
425 Britannia Road E
Suite 121
Mississauga, Ontario
L42 3E7
(416) 890-9244

JOE SLANEY
Vice-President
BARCLAYS BANK
OF CANADA
Suite 602, TD Place
140 Water Street
St. John's, NF
A1N 3Y8
(709) 753-9641

ROBERT J. SLAYMAKER
Senior Manager
BARCLAYS BANK
OF CANADA
P.O. Box 377
Commerce Court
Postal Station
Toronto, Ontario
M5L 1G2
(416) 862-0594

SHEILA SMITH
Tax Manager
CLARKSON GORDON
10 Fort William Place
St. John's, NF
A1C 1K4
(709) 726-2840

ALFRED A. SMITHERS
President
SECUNDA MARINE
SERVICES LIMITED
P.O. Box 605
Dartmouth
Nova Scotia
B2Y 3Y9
(902) 465-3400

FRANK SMYTH
Manager
Engineering Offshore
Development Division
DEPT OF DEVELOPMENT
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-2785

FRANK SOMMERVILLE
Senior Manager
DEPT. OF INDUSTRY,
TRADE & TECHNOLOGY
P.O. Box 519
Halifax, Nova Scotia
B3J 2R7
(902) 424-4730

RONALD SOROKAN
DRECO ENERGY SERVICES
3716-93rd Street
Edmonton, Alberta
T6E 5N3
(403) 463-2065

LORNE SPRACKLIN
Assistant Deputy
Minister
DEPT OF MINES & ENERGY
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-2348

DOUGLAS SQUIRES
Head, Electrical
Engineering Technology
MARINE INSTITUTE
P.O. Box 4920
St. John's, NF
A1C 5R3
(709) 778-0323

JACK C. STAMBERG
Manager, Project
Engineering
GULF CANADA RESOURCES
LIMITED P.O. Box 130
Calgary, Alberta
T2P 2H7
(403) 233-4000

MARK STAPLE
Vice President
INTERNATIONAL
MANAGEMENT SERVICES
GROUP INC. Suite 630
Cabot Place, Gower St.
St. John's, NF
A1C 1J3
(709) 579-5492

(*)**TOR HENRIK STAVNES**
Document Administration
Supervisor
INECO A/S
P.O. Box 200
N. 1321 Stabekk
Norway
47-02-598100

WAYNE C. STOCKWOOD
Production Manager
DEPT. OF DEVELOPMENT
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-2800

GEORGE L. STONE
President
G. L. STONE ENTERPRISES
P.O. Box 1126, Stn. B
Mississauga, Ontario
L4Y 3W4
(416) 277-8181

JAMES STRAIN
Chairman
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF A1C 6H6
(709) 778-1400

(**)**ROB STRONG**
Manager
Business Development
CAPITAL CRANE LIMITED
P.O. Box 8274, Stn A
St. John's, NF
A1B 3N4
(709) 782-3404

STEWART STRONG
Engineer
SHAWMONT NEWFOUNDLAND
LIMITED
P.O. Box 9600
St. John's, NF
A1A 3C1
(709) 754-0250

(*)**KJETIL STULAND**
Management Director
NO-HA ENGINEERING A/S
Maskinvelen 12
P.O. Box 4
4033 Forus
Norway
47-04-800860

CYRIL STURGE
Director
DEPT OF MINES & ENERGY
P.O. Box 8700
St. John's, NF
A1B 4J6
(709) 576-3605

JOHN SWEETLAND
Western Regional Manager
DEPT. OF DEVELOPMENT
Suite 502, Herald Towers
P.O. Box 2006
Corner Brook, NF
A2H 6J8
(709) 637-2280

ANDRE TASCHEREAU
MIL TRACEY INC.
P.O. Box 550
Sorel, Quebec
J3P 5P5
(514) 743-3351

WILLIAM L. TELL
Sales
CONSOLIDATED PRODUCTS
SOUTH BAY CABLE DIVISION
28366 Chia Trail
Hemet, California
U.S.A. 92344
(714) 652-0311

(*)**TERJE TELLEFSEN**
Vice President, Offshore
A/S UGLANDS REDERI
P.O. Box 128
4891 Grimstad
Norway
47-04-140011

(*)ARILD THORSRUD
Manager
Technological
Development
AKER DRILLING A/S
Plattfornveien 2-4
Postboks 65
4056 Tananger
Norway
47-04-696766

MAGNE TORHAUG
Manager, Risk &
Reliability Services
DET NORSKE VERITAS
CANADA LTD.
#1110, 10201
Southport Road SW
Calgary, Alberta
T2W 4X9
(403) 253-3422

LEIF E. TORKELSEN
Project Manager
MOSS ROSENBERG
P.O. Box 139
N-4001 Stavanger
Norway
47-04-865000

CAPTAIN MARK TURNER
MARINE INSTITUTE
P.O. Box 4920
St. John's, NF
A1C 5R3
(709) 778-0395

CLAUDE VALENCHON
Engineer
BOUYGUES OFFSHORE
78884 St. Quentin
Yvelines, FRANCE
(33) 1 30608888

DR. G. VAN OORTMERSSEN
MARITIME RESEARCH
INSTITUTE NETHERLANDS
P.O. Box 28, 6700 AA
Wageningen
THE NETHERLANDS
(31) 8370 93911

GARY VERBRUGH
Project_Manager
FLAKT ROSS INC.
304 St. Patrick
LaSalle, Quebec
H8N 2H1
(514) 366-5160

GUS VOETELINK
President
MICOPERI USA CORP.
525 North Belt East
Suite 600
Houston, Texas
77060   U.S.A.
(713) 999-0046

IAN C. WALLACE
Lawyer
STIRLING, RYAN
P.O. Box 5038
St. John's, NF
A1C 5V3
(709) 722-4270

PAUL WEATHERBY
Manager, Quality
Assurance
NORDCO LIMITED
P.O. Box 8833
St. John's, NF
A1B 3T2
(709) 364-1200

KEVIN WHITTLE
Senior Officer
CANADA-NEWFOUNDLAND
OFFSHORE PETROLEUM
BOARD
140 Water Street
St. John's, NF
A1C 6H6
(709) 778-1439

JIM WILSON
TOPSIDE CONTRACTORS
OF NEWFOUNDLAND
LIMITED
P.O. Box 5680
St. John's, NF
A1C 5W8
(709) 579-2010

(*)PAUL WILSON
NORTEK
ENGINEERING INC.
220 LeMarchant Road
St. John's, NF
A1C 2H8
(709) 739-6749

DENIS ZBOROWSKI
Communications Man.
CANADA OIL & GAS
LANDS ADMINISTRATION
355 River Road
Tower B
Ottawa, Ontario
K1A 0E4
(613) 991-5940